SANDIA REPORT
SAND2014-18540
Unlimited Release
Printed September 2014

Comparing Conventional, Modular and Transportable Electric Transmission and Distribution Capacity Alternatives Using Risk-adjusted Cost

A Study for the DOE Energy Storage Systems Program and for the California Energy Commission's Public Interest Energy Research (PIER) Program

Jim Eyer and Jacquelynne Hernández

Prepared by
Sandia National Laboratories
Albuquerque, New Mexico 87185 and Livermore, California 94550

Sandia National Laboratories is a multi-program laboratory managed and operated by Sandia Corporation, a wholly owned subsidiary of Lockheed Martin Corporation, for the U.S. Department of Energy's National Nuclear Security Administration under contract DE-AC04-94AL85000.

Sandia National Laboratories

Issued by Sandia National Laboratories, operated for the United States Department of Energy by Sandia Corporation.

Available to DOE and DOE contractors from
U.S. Department of Energy
Office of Scientific and Technical Information
P.O. Box 62
Oak Ridge, TN 37831

Telephone: (865) 576-8401
Facsimile: (865) 576-5728
E-Mail: reports@adonis.osti.gov
Online ordering: http://www.osti.gov/bridge

Available to the public from
U.S. Department of Commerce
National Technical Information Service
5285 Port Royal Rd.
Springfield, VA 22161

Telephone: (800) 553-6847
Facsimile: (703) 605-6900
E-Mail: orders@ntis.fedworld.gov
Online order: http://www.ntis.gov/help/ordermethods.asp?loc=7-4-0#online

SAND2014-18540
Unlimited Release
Printed September 2014

Comparing Conventional, Modular and Transportable Electric Transmission and Distribution Capacity Alternatives Using Risk-adjusted Cost

A Study for the DOE Energy Storage Systems Program
and for the California Energy Commission's
Public Interest Energy Research (PIER) Program

Jim Eyer E&I Consulting
Distributed Utility Associates

Jacquelynne Hernández
Sandia National Laboratories

ABSTRACT

The primary topic addressed by this report is the use of modular distributed energy resources (DERs) to reduce investment risk associated with electric utility transmission and distribution (T&D). A secondary theme addressed by this report is the possible financial benefit associated with use of transportable DERs as marginal capacity in lieu of additional T&D equipment. The report includes a characterization of a basic framework for estimating the risk-adjusted cost for various alternatives that could serve peak demand, on the margin, for one year including: 1) do nothing, 2) upgrade the T&D equipment, and 3) utilize various amounts of DER capacity.

ACKNOWLEDGMENTS

This work was sponsored by the California Energy Commission (CEC) Public Interest Energy Research (PIER) program and the United States Department of Energy (DOE) Energy Storage Systems Program under contract to Sandia National Laboratories (SNL).

The authors would like to thank Dr. Imre Gyuk of DOE and Dan Borneo of SNL, as well as Pramod Kulkarni, Mike Gravely and Mark Rawson at the CEC for their support of this work. Special thanks go to Paul Butler of SNL and Garth Corey, formerly with SNL, for their thorough and insightful reviews. The authors also received valuable support from Nancy Clark, formerly with SNL, throughout the development of this report.

The authors gratefully acknowledge the contributions of Roger Pupp, Ph.D. and Thomas E. Hoff, Ph.D. Both Roger and Tom provided invaluable guidance. Tom Dossey of Southern California Edison Company (SCE), Eric Wong of Cummins Power Generation and Lloyd Cibulka of the California Institute for Energy and Environment (CIEE) also provided very helpful support and review.

Invaluable assistance was provided by Jim Skeen, renowned electric utility distribution and power engineer and economist. Jim provided especially important assistance with engineering related assumptions and factors such as the effects of T&D equipment overloading.

SNL is a multi-program laboratory operated by Sandia Corporation, a Lockheed Martin Company for the United States Department of Energy's National Nuclear Security Administration under Contract DE-AC04-94AL85000.

Contents

FIGURES

TABLES

Executive Summary

Introduction

This report characterizes a framework for assessing the risk-adjusted cost of three alternative approaches to addressing peak demand for electric power that is served by electrical transmission and distribution (T&D) equipment. The alternatives are: 1) do nothing, 2) undertake a conventional T&D upgrade involving wires and/or transformers to add capacity to the existing T&D equipment; and 3) serve peak demand – on the margin – using modular capacity from distributed energy resources (DERs).

DERs used may include one or more of the following: distributed generation (DG), geographically targeted energy efficiency (EE), geographically targeted demand response (DR) or distributed electricity storage (DES). Distributed generation and electricity storage could include stationary and/or transportable solutions.

This report also provides an introduction to the prospect of using a fleet of transportable DERs to provide modular electrical T&D capacity.

Introduction to Risk

Fundamentally, risk is the potential for a specific endeavor or activity to lead to one or more undesirable outcomes. *Financial* risk involves a combination of higher than expected cost and/or lower than expected benefits. Underpinning risk is uncertainty about one or more factors that affect the ultimate cost and ultimate benefit for a given business endeavor.

For example, actual financial returns associated with a business endeavor may involve uncertainty about one or more of the following: 1) unforeseen costs that may be incurred such as the need for additional equipment or facilities; 2) the future price for inputs used for the endeavor such as energy, materials and labor; and 3) future demand and allowable price for the endeavor's output.

Scope and Purpose

The primary purpose of this report is to characterize the *concept* of comparing electric utility T&D capacity alternatives, based on risk-adjusted cost, using a realistic framework and assumptions. (Risk-adjusted cost is defined as the alternative's direct cost *plus* its estimated financial risk.) This comparison serves to identify the alternative with the lowest risk-adjusted cost when and where the utility needs additional T&D load-carrying capacity "on the margin."

The following alternatives are compared: 1) do nothing, 2) upgrade the T&D equipment to add capacity using conventional means and 3) use modular DERs which could provide incremental load-carrying capacity.

Key themes addressed include 1) characterization of a framework for estimating risk-adjusted cost for alternatives that could be used to serve peak load on the margin, 2) sources of uncertainty related to T&D planning and a discussion of related risk and 3) an example case involving a comparison of those alternatives, given uncertainty, on a risk-adjusted cost basis.

A secondary purpose of this report is to provide a high-level characterization of the reasons why using transportable generation and storage might be an attractive way to deploy modular/distributed resources. Consequently, this report also includes a high-level characterization of the merits of DER transportability, including increased life-cycle benefits relative to those possible using stationary or permanent systems.

Premises

The overarching premise for the approach described herein is that the concept addressed – comparing alternatives for providing T&D capacity, on the margin, using risk-adjusted cost – reflects an innovative, economically superior and possibly compelling way of evaluating alternatives, in part, by considering effects from several sources of uncertainty.

Conversely, it is important to acknowledge that there is risk associated with all alternatives. To the extent that utility T&D capacity planners can robustly evaluate uncertainty and risk, they can manage, accept or share risk when prudent and cost-effective.

Another key premise is that using risk-adjusted cost as the basis for utility T&D investment decisions leads to lower overall utility cost-of-service – especially when implemented across the utility's portfolio of T&D investments.

Additionally, using transportable, modular capacity to serve some load on the margin increases the prospects for deriving benefits of those alternatives that are commensurate with the relatively high cost for modular capacity alternatives.

The approach described in this report may be especially compelling given the evolution of the electricity marketplace that is driven by several important factors, especially

- Emerging *modular* electric power technologies, particularly distributed generation (DG) and distributed electricity storage (DES)
- Numerous manifestations and components of Smart Grid
- Increasingly powerful analytical tools (*e.g.*, for power engineering and design, capacity planning and financial analysis)
- T&D capacity congestion and T&D upgrade-related constraints
- Increasing emphasis on distribution management systems (DMS) including predictive maintenance protocols, remaining life estimation, and Volt/VAR control
- Increasing uncertainty, about considerations such as environment, fuel price and availability, electric supply sources and cost and changing electricity end-user preferences

Intended Audience

The audience for this report includes utility distribution planners and engineers, utility finance staff, regulatory and policy stakeholders with an interest in DERs and/or T&D planning and finance and DER vendors seeking a richer understanding of the DER value proposition.

Risk-adjusted Cost Evaluation

The Example Case

This report will demonstrate the approach and framework using an example case that is intended to be realistic. It includes explicit consideration of sources of uncertainty that affect utilities' T&D capacity-related decisions such as the following:

- Inherent peak demand growth
- Block load additions (magnitude and timing)

- Weather
- Resources' availability (*e.g.*, engineering and construction staff, capital, etc.)
- Project delays (*e.g.*, related to permitting, new information or shifting utility priorities)

The costs for 1) the do nothing alternative, 2) a conventional T&D upgrade and 3) various modular DER alternatives will also be addressed.

In the example case: The existing T&D equipment is rated at 12,000 kW and current-year peak load that is about 97.5% of the T&D equipment's load-carrying capacity. That peak load is growing at an expected rate of 1.7% per year. Peak load may exceed the equipment's rating in the next year. Various alternatives to address the expected overload evaluated include 1) do nothing; 2) proceed with the standard upgrade of the equipment (by adding more conventional T&D equipment/capacity) whose incremental cost is $210/kW added ($52.5/kW of total installed capacity); or 3) use modular DER capacity to serve peak demand on the margin (*i.e.*, load exceeding the T&D equipment's rated load-carrying capacity) during the next year.

Importantly, the evaluation addresses circumstances in one *specific* year – in the example, it is the "next" year when end-user demand is expected to exceed the load carrying capacity of the existing T&D equipment. So, the evaluation described in this report must be undertaken for *each* year of interest because the cost/benefit relationship for each alternative evaluated changes from one year to the next. For example, in many cases, the do nothing alternative and deploy DER capacity alternatives are only competitive for one or two years before an upgrade of the T&D equipment becomes the best alternative (*i.e.*, as peak demand grows, the net benefit per kW of DER diminishes in subsequent years because the risk associated with the do nothing alternative increases each year, and the amount of DER capacity needed increases each year).

Uncertainty and Loading

The characterization of T&D-related uncertainty includes results shown below in Figure ES-1. Specifically, Figure ES-1 shows the various possible levels of maximum overloading of the existing T&D equipment for the do nothing alternative, for the 27 scenarios considered in the example case. Also shown are a) the probability that any individual scenario will come to pass and b) the cumulative probability for a given level maximum overload.

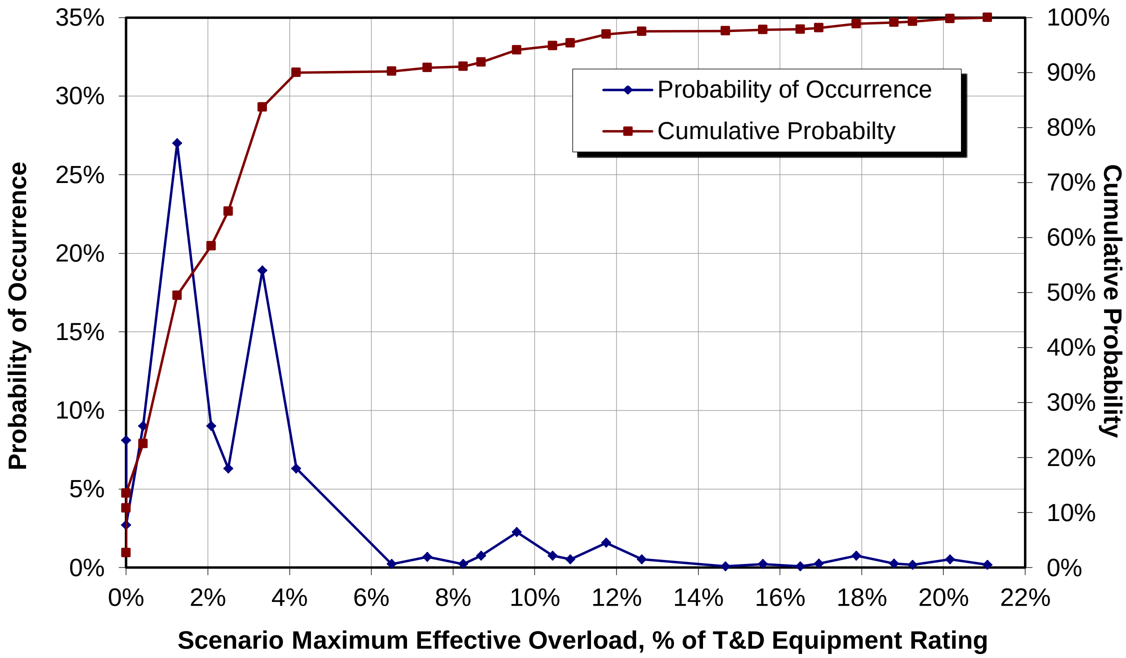


FIGURE ES-1. OVERLOADING AND PROBABILITIES.

Shown in Figure ES-1: Of the 27 scenarios evaluated, there are eight for which the maximum effective overload in the next year would not exceed the “overload floor” of 4%. (For this report, it is assumed that overloading of less than the overload floor does not cause damage or electric service outages.) Those eight scenarios are plotted on the lower far left quadrant of the figure. Given the combined probability of occurrence associated with those eight scenarios (about 84% cumulative probability), it is quite likely that that there will not be damage or service outages for the do nothing alternative.

Conversely, the figure also shows 19 scenarios for which the maximum effective overload exceeds the overload floor of 4%. For those 19 scenarios, there is T&D equipment damage and in some cases (involving overloading in excess of the “overload ceiling” of 10%) outages occur. Importantly, there is a relatively low probability (about 16%) that any one of those 19 scenarios would occur. There is an even lower probability (5.9%) that the maximum effective overload will exceed the 10% overload ceiling, meaning that electric service outages are quite unlikely.

Risk-adjusted Cost Evaluation Results Summary

Figure ES-2 shows the scenario-specific maximum effective overload and the resulting cost values for the do nothing alternative. (Associated probabilities are shown above in Figure ES-1.)

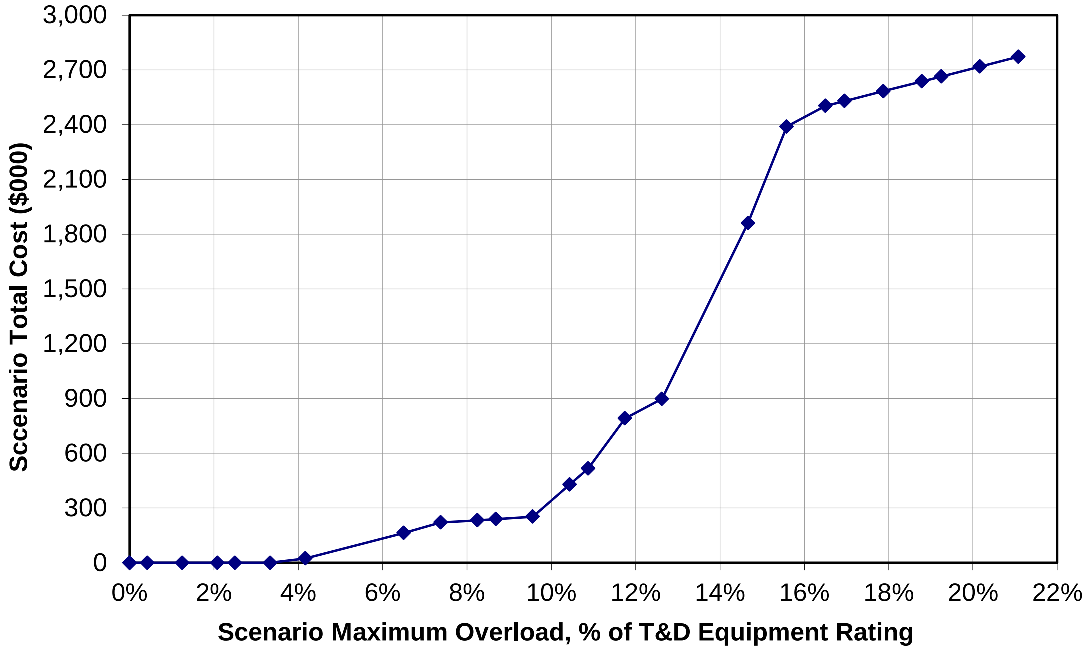


FIGURE ES-2. SCENARIO-SPECIFIC MAXIMUM OVERLOAD AND RESULTING COST.

Figure ES-3 shows how the total risk diminishes as more and more DER capacity is added for the example case. (Adding DER has the effect of decreasing the maximum overload that would occur). The value in the upper left of that figure reflects risk associated with no DER capacity, which is equal to the risk for the do nothing alternative ($99,116).

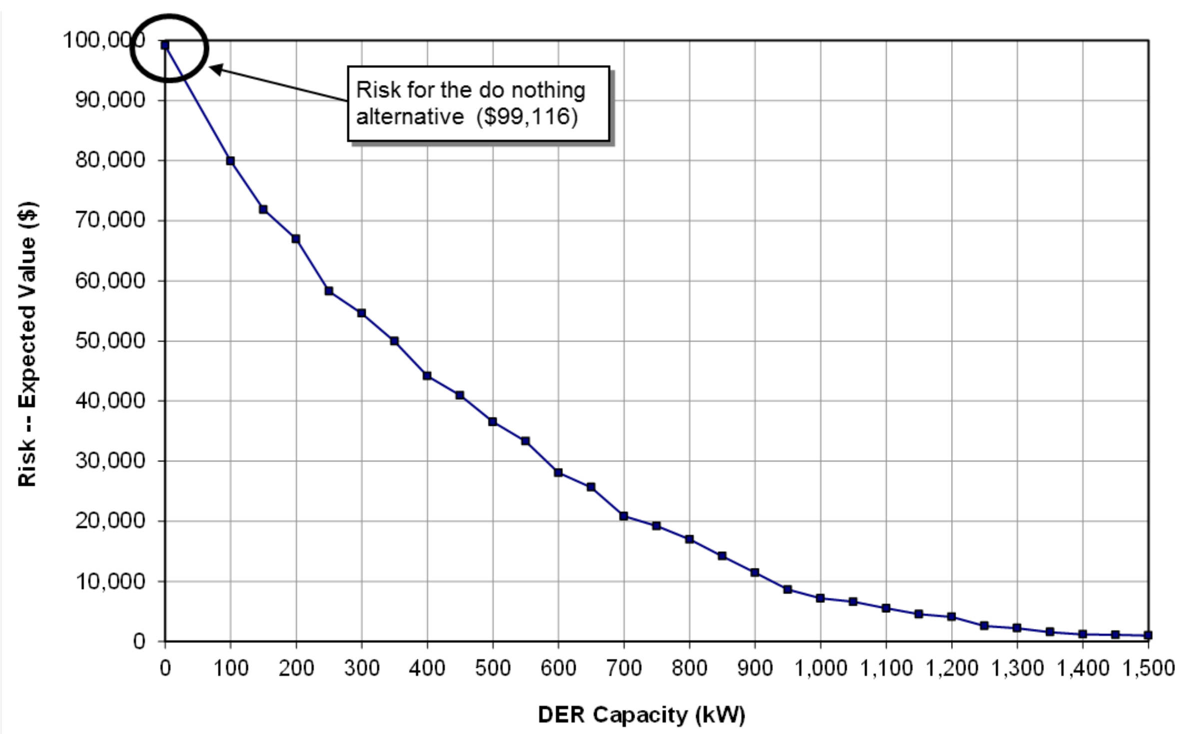


FIGURE ES-3. RISK FOR VARIOUS LEVELS OF DER CAPACITY DEPLOYED.

Figure ES-4 shows results – for the example case evaluated – involving various amounts of generic, totally reliable ("perfect") DER capacity. The lower of the two straight plot lines (labeled "Do Nothing") shows the risk for the do nothing alternative for the one year being evaluated. That cost is $99,116 per year. The upper straight plot line (labeled "Upgrade Cost") shows the single-year-specific risk-adjusted cost (direct cost *plus* risk) for the proposed T&D upgrade of $107,267.

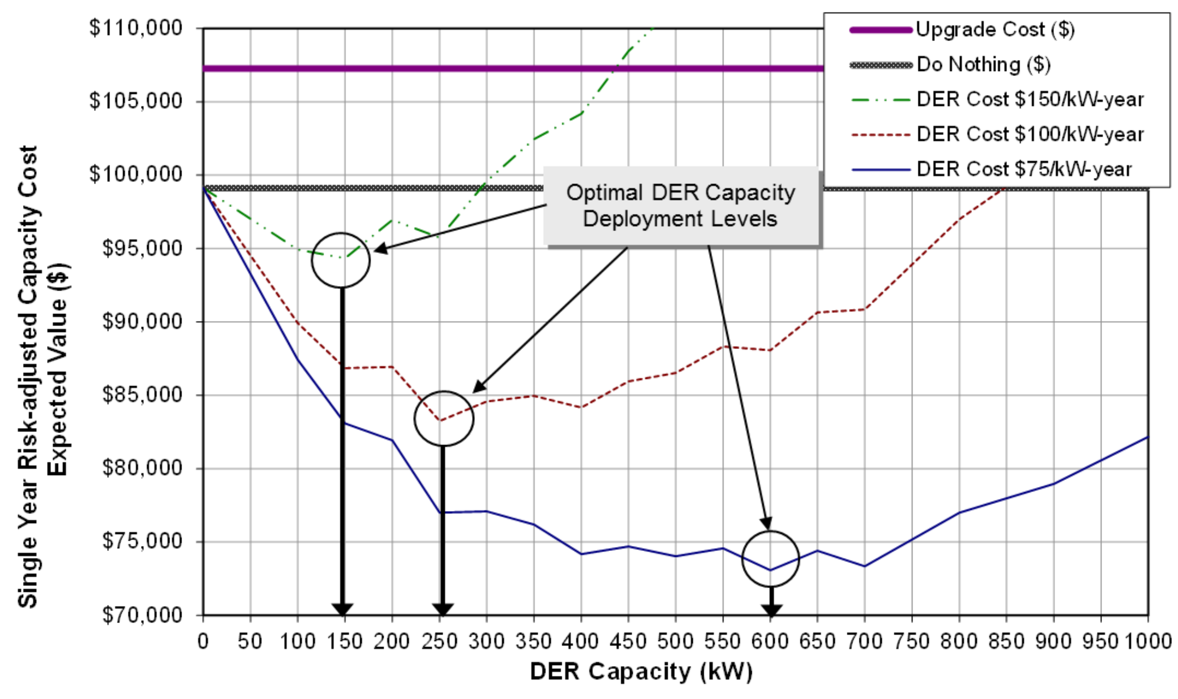


FIGURE ES-4. SINGLE-YEAR RISK-ADJUSTED COST FOR T&D CAPACITY ALTERNATIVES.

The three curved plots show the risk-adjusted cost for various amounts of *generic* DER, for the year being evaluated, for the example case. Specifically, those plots show risk-adjusted cost for perfect DERs whose annual total direct cost (*i.e.*, total cost to own and to operate the DER) is $75/kW per year ($75/kW-year), $100/kW-year and $150/kW-year.

Risk-adjusted cost minima are shown (circled) for the three DER plots. At those points, the risk-adjusted cost for perfect DER capacity is minimized for the respective DER's annual direct cost.

There are at least two notable observations based on Figure ES-4. First, for the specific year evaluated, the do nothing alternative has a lower risk-adjusted cost than the T&D upgrade. Second, as one would expect, the optimal amount of DER capacity (*i.e.*, the capacity that results in the lowest risk-adjusted cost) is a function of the DER's direct cost.

If perfect DER capacity's "all-in" direct cost is $150/kW-year, then the optimal DER deployment (on a risk-adjusted cost basis) is 150 kW. That DER would have a direct cost of $22,500 for one year and the risk (due to undersizing) is about $71,842. So, for 150 kW of perfect DER costing $150/kW-year, the single-year risk-adjusted cost is about $94,342 – which is somewhat more competitive than the do nothing alternative (whose risk-adjusted cost is $99,116).

For perfect DERs whose annual total direct cost is $100/kW-year, the optimal DER deployment (on a risk-adjusted cost basis) is 250 kW. The direct cost for that DER is $25,000 and the risk due to undersizing is $58,246 for a total risk-adjusted cost of $83,246. By comparison, that is lower than the risk for doing nothing ($99,116) by $15,870 (16%).

Finally, if a perfect DER's annual all-in direct cost is $75/kW-year, then the optimal amount of DER is 600 kW. The direct cost is $45,000 per year, and the risk related to undersizing is $28,072 for a total risk-adjusted cost of $73,072 for the year. That is lower than the do nothing alternative by $99,116 - $73,072 = $26,044 (about 26.3%).

This analysis – involving *generic* DERs with perfect reliability – provides a general indication of the relationship between DER cost and the optimal amount of DER (capacity) to install. However, eventually the evaluation has to address *actual* DERs (*i.e.*, DERs that are available and that can be deployed). That exercise is the culmination of the evaluation undertaken to identify the deployable alternative with the lowest risk adjusted cost.

The four real alternatives that are compared for the example case, including two with actual DERs, are

1. Do nothing.
2. Do the T&D upgrade.
3. Rent two 250 kW (500 kW total) diesel engine generator sets (gensets), one for the three hottest months of the year and one for the five hottest months of the year.
4. Rent one 250 kW genset for the three hottest months of the year and one 350 kW genset (600 kW total) for the five hottest months of the year.

In addition to those four real alternatives, two hypothetical alternatives are evaluated: 1) 500 kW of perfect (*i.e.*, perfectly reliable) DER costing $100/kW-year and 2) 600 kW of perfect DER whose cost is $100/kW-year. (Those two perfect DER alternatives could represent demand response resources.)

(Note that 500 kW is about 4.2% of the existing T&D capacity of 12,000 kW and 600 kW is about 5% of the existing T&D capacity. That compares to a probability-weighted [expected value] for maximum effective overload of 339 kW [2.82%] for the example case.)

The risk-adjusted cost evaluation culminates with a comparison of alternatives' risk-adjusted net cost, which includes risk, direct cost and a credit for energy produced (if any). Of course, the energy credit only applies if the DERs are actually operated and if the DERs actually produce energy output. The comparison is shown graphically in Figure ES-5.

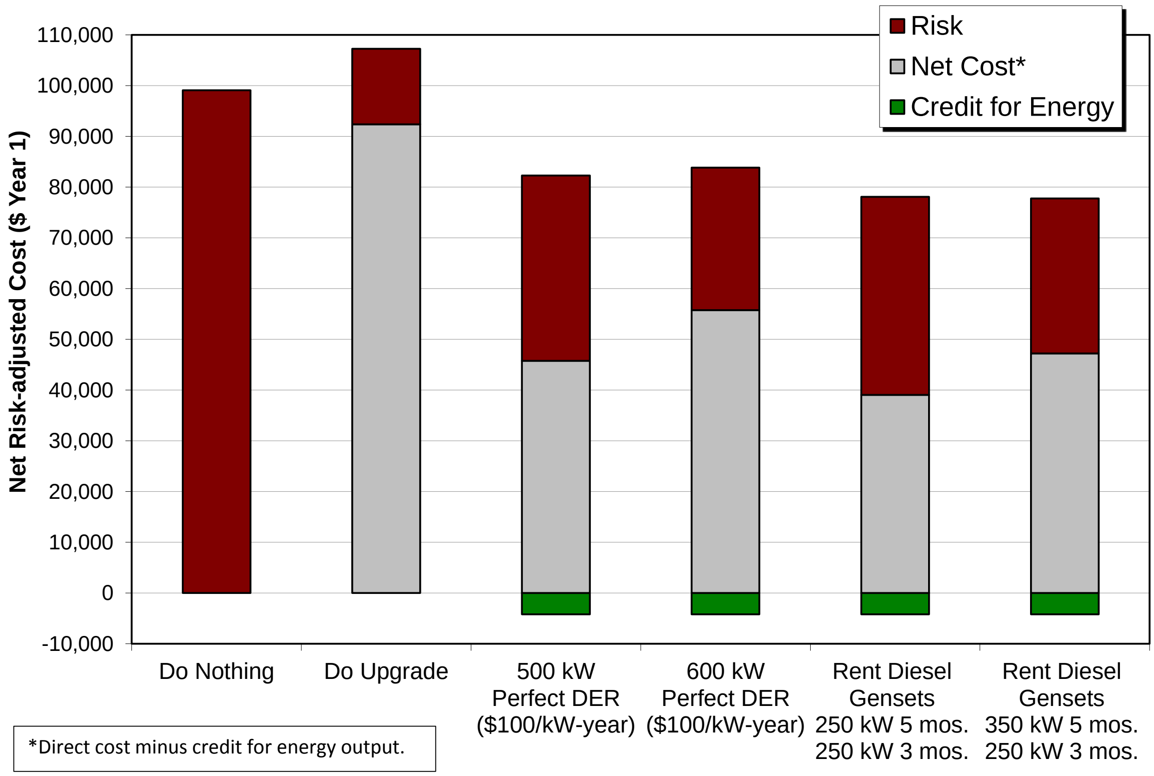


FIGURE ES-5. SINGLE-YEAR RISK-ADJUSTED NET COST COMPARISON OF ALTERNATIVES.

The risk-adjusted net cost for 500 kW of perfect DER costing $100/kW-year is $82,313. That is $24,995 (23.3%) lower than the cost for the do upgrade alternative and $16,804 (17%) lower than the cost for do nothing. For 600 kW of perfect DER (costing $100/kW-year), the risk-adjusted net cost is $83,853 which is about $23,415 (21.8%) lower than for the upgrade and $15,264 (15.4%) lower than doing nothing.

Renting one 250 kW diesel genset for three months and an additional 250 kW genset for five months has a risk-adjusted net cost of $78,080. That is $29,187 (27.2%) lower than doing the upgrade and $21,036 (21.2%) lower than doing nothing.

The alternative involving rental of two gensets – 250 kW for three months and 350 kW for five months – has the lowest risk-adjusted net cost: $77,761, which is about $29,507 (27.5%) lower than doing the upgrade and almost $21,356 (21.5%) lower than doing nothing.
(See Appendix G for details about the gensets' rent, operation hours and energy production.)

Risk for T&D Oversizing

Not addressed in this report: A potentially significant risk related to any T&D upgrade investment is that the upgrade may be undertaken before it is actually needed (*e.g.*, peak demand does not grow as fast as expected or if block load additions are delayed). In some cases, the upgrade may not be needed at all (*e.g.*, if there is no peak demand growth or if expected block load additions do not come to fruition). In either case, there is financial risk related to the underutilized capacity (*i.e.*, there is no revenue associated with the capacity added).

Key Conclusions

Risk-adjusted Cost

Several conclusions can be drawn based on the results of this work. Perhaps the most important conclusion is that use of risk-adjusted cost does not simply provide a better way to identify a solution. Rather, it increases the alternatives available to the T&D planner to address capacity-constrained situations.

In the past, when peak loading on a T&D node approached the T&D equipment's load-carrying limit, the two primary alternatives available to the T&D planner were to 1) upgrade the system – usually by adding a relatively large amount (a.k.a. "lump") of capacity using conventional T&D equipment or 2) do nothing and hope that capacity limits are not exceeded. Including modular DER alternatives in the evaluation provides a much richer range of possibilities.

When an upgrade is or will be imminent, T&D planners may include DER capacity – deployed to defer the need for the upgrade by serving marginal peak demand in the next year – in their evaluation of alternatives.

The optimal amount of DER for any given circumstance is largely a function of the DER annual cost. As illustrated in Figure ES-4: The lower the DER annual cost, the more DER that should be installed. This is because, for a given amount of DER capacity, there is a trade-off between the potential economic consequences of an overload and the cost associated with the DER investment.

These results provide T&D planners, policymakers and researchers with a basis for further consideration of the concept as an important element of the utility T&D planning framework. Other considerations also make this concept attractive as a topic for further development:

1. Though estimating the greater economic value of this approach is beyond the scope of this report, presumably the stakes are large – well into the billions of dollars.
2. Though the risk-adjusted cost approach is a departure from traditional T&D expansion planning practices that are based on rules and reliability benchmarks—
    - The risk-adjusted cost approach has characteristics in common with existing T&D planning approaches. Most notable is the need to address planning uncertainties and to effectively accommodate an increasing array of technically viable DERs.
    - The risk-adjusted cost approach is consistent with emerging T&D planning techniques that are more sophisticated, incorporating predictive maintenance and other statistical, modeling, and financial approaches to optimizing T&D capacity use and life.
3. It seems important to consider more explicit and transparent treatment of risk as an element of sophisticated treatment of T&D (services) pricing.
4. Even greater cost reductions than those indicated by the single-year evaluation undertaken for this study may accrue for a multi-year build-out of utility T&D capacity using modular resources.
5. The electrical grid of the future will involve more complexity, more uncertainty and more dynamic influences. To accommodate these changes, presumably, utility operators and planners will make more use of stochastic models and evaluation frameworks, rather than

relying on approaches that are deterministic and/or that emphasize solutions for the "worst case".

Although not addressed directly in this report, a significant installed base of DERs could be an element of electric supply and/or fuel-related risk management strategies, depending on the type of DER and fuel used.

Transportability

While not common practice today, the use of transportable, modular DERs to serve localized peak demand on the margin could become an important element of the grid of the future. One important reason to use transportable DERs is that they provide utilities – and possibly even electricity end-users – with more flexibility than stationary DERs. That flexibility may be important as utilities must address increasing competition and uncertainty from several sources including capital markets and regulation and customer-owned and third-party-owned DERs.

Consider that transportable DER capacity can be quickly deployed when and where needed. DERs in a fleet (*i.e.*, multiple DERs) could be redeployed or removed easily. Transportable DERs can be used several or even many times, increasing the chance that life-cycle benefits will exceed cost. For example, the same DER capacity could be used at different locations throughout its lifetime. Also, transportable DER capacity could be used a) during summer for locations that have a significant peak demand related to air conditioning and then b) redeployed later in the year (after summer) to locations with a high winter peak demand.

Key Caveats

Readers are urged to consider that using a risk-adjusted cost comparison to identify the most attractive alternative for serving customer demand on the margin is not common practice.

Indeed, the presentation of the concept in this report is meant to indicate a new way of thinking about T&D capacity expansion – one that involves incremental, "just-in-time" capacity additions and a more explicit characterization of the risk associated with T&D investments.

The risk-adjusted cost comparison approach is not common practice for several reasons. First, utility regulations typically do not address T&D investment risk fully or robustly. Second, use of most modular capacity alternatives (*e.g.*, distributed generation or electricity storage and geographically targeted demand response) is not common, especially as a way to serve demand on the margin of T&D capacity. Third, most utilities do not have "regulatory permission" to use modular capacity within specific parts of the T&D system.

It is also important to note that some of the data and calculations used herein to demonstrate the concept required simplifying assumptions and approaches, as well as engineering judgment. Especially notable are data and/or approaches used to estimate the following:

- Customer outage-related costs
- Effects of high ambient temperature on peak demand
- The magnitude and frequency of peak demand
- Cost related to damage to the existing T&D equipment resulting from overloading, including existing life and remaining value
- T&D equipment derating due to high ambient temperatures

Nonetheless, the authors firmly believe that the concept of comparing alternatives on a risk-adjusted cost basis is at least somewhat compatible with existing regulations and emerging utility practices. Furthermore, such an approach is becoming more practical given technological advances and changes in the electricity marketplace, such as a) improving means to undertake predictive maintenance with potential to assess T&D equipment's remaining life, b) increasingly sophisticated T&D planning tools, c) the accelerating move to Smart Grid and d) emerging interest in modular/distributed alternatives to central generation and to T&D capacity.

NOMENCLATURE

Acronyms and Abbreviations

A/C	air conditioning
CPP	critical peak pricing
DER	distributed energy resource
DES	distributed electricity storage
DESS	distributed electricity storage system
DG	distributed generation
DISCO	distribution company
DMS	distribution management system
DPA	distribution planning area
DR	demand response
EE	energy efficiency
FCR	fixed charge rate
genset	engine/generator “set" (system)
I/C	interruptible or curtailable (load programs)
IEEE	Institute of Electrical and Electronics Engineers
IOU	investor-owned utility
kV	kilovolt
kVA	kilovolt-Ampere (aka: kilovolt-Amp)
kW	kilowatt
kWh	kilowatt-hour
LDC	load-duration curve
LMP	locational marginal pricing
MDCC	marginal distribution capacity cost
MES	modular electricity storage
MW	megawatt
MWh	megawatt-hour
O&M	operations and maintenance
PIER	Public Interest Energy Research Program
RAP	Regulatory Assistance Project
SAIDI	System Average Interruption Duration Index
SAIFI	System Average Interruption Frequency Index
T&D	transmission and distribution
UPS	uninterruptible power supply
VAR	volt-Ampere reactive
VPP	virtual power plant

Glossary

Ancillary Services – Those services necessary to support the transmission of electric power from seller to purchaser given the obligations of control areas and transmitting utilities within those control areas to maintain reliable operations of the interconnected transmission system. (As defined by the Federal Energy Regulatory Commission, FERC)

Avoided Cost – A cost that can be avoided if an alternative (including doing nothing) is used.

Block Load Addition – An entirely new load that is to be connected to the electricity grid. Examples include one-time load additions involving new commercial and housing developments or new equipment with a large power draw relative to the load-carrying capacity of the T&D equipment that serves the load.

Capacity – The amount of utility infrastructure needed to generate, transmit or deliver electric energy to customers. Generation, wires and transformers are rated in units of *real* power (*e.g.,* kiloWatts or MegaWatts) or *apparent* power (*e.g.,* kiloVolt-Amperes or kVA).

Capacity Credit – The degree to which a given portion of the electricity infrastructure provides *capacity value*. For example, during some days wind generation only generates electricity at a rate that is 20% of its maximum rate (maximum rated power output). That resource has a capacity credit of about 20%.

Capacity Value – The financial value associated with additional capacity in a given portion of the utility infrastructure. Often the value is related to the avoided cost for the most likely alternative. For example, if a utility needs additional generation capacity to serve peak demand on the margin then the value of additional capacity might be pegged at the cost for a) a simple cycle combustion turbine or b) additional demand response resources (*i.e.,* whichever is assumed to be the "proxy" or default capacity resource).

Case – The specific circumstance (year, location, node within the grid) being evaluated (also referred to as "the example case").

Carrying Charges – The annual financial requirements needed to service debt or equity capital used to purchase and to install the storage plant, including tax effects. For utilities, this is the revenue requirement. See also *Fixed Charge Rate*.

Cost of Capital – The annual interest rate and/or stock dividend rate.

Critical Peak Pricing (CPP) – A "very high" price for electric energy that prevails during times when electric supply resources and/or transmission capacity are in short supply.

Demand – The maximum power draw by electricity end-users during a specific period of time. Normally expressed in units of kilowatts (kW) or megawatts (MW). See also *Load*.

Demand Response (DR) – Controlled reduction of power draw by electricity end-users' electricity-using loads (sometimes referred to as responsive loads), accomplished via communication and control protocols, done in part or primarily to balance real-time demand and supply or *in lieu* of adding generation and/or T&D capacity.

Derating – Reduced load-carrying capacity due to various circumstances, for example, high ambient temperature.

Design Temperature – The ambient temperature assumed when establishing power draw, generation capacity or T&D load-carrying capacity (design rating).

Distributed Energy Resource (DER) – An electric resource (*e.g.,* demand response, distributed generation or distributed energy storage) that is located at or near loads – usually within or at the end of the electrical distribution system.

Distributed Generation (DG) – A type of distributed energy resource (DER) that converts energy in a fuel (*e.g.,* natural gas) to electricity.

Distribution Company (DISCO) – A utility entity whose responsibilities include distribution of energy and customer service.

Distribution Planning Area (DPA) – A *specific* portion of the utility service area which is served by a *specific* part of the utility's distribution infrastructure.

Distribution – See *Electrical Distribution*.

Direct Cost – The sum total of all costs to own or to rent an alternative, including some or all of the following: rental charges, equipment purchase and delivery cost, project design, installation, depreciation, interest, dividends, taxes, service, consumables, fees, permits and insurance. Direct cost reflects point estimates of future values without regard to uncertainty.

Effective Overload – Electricity end-user demand (power draw) that exceeds the T&D equipment's load-carrying capacity, after accounting for the effects of high temperature, such as a) increased end-user demand related to space air conditioning and refrigeration and b) reduced T&D equipment load-carrying capacity, relative to the design temperature. Effective overload is expressed as either a) a specific power level and/or b) a percentage of the T&D equipment's design rating.

Electrical Distribution – Electrical distribution is used to send relatively small amounts of electricity over relatively short distances for delivery of electricity to end-users. It is connected to the transmission system. In the United States, distribution system operating voltages generally range from several hundred volts to 50 kV (50,000 V).

Electrical Equipment Power Rating (Rating) – The amount of power that can be delivered under specified conditions. The most basic rating is an equipment "nameplate" rating – the equipment's nominal power delivery rate under "design conditions." Other ratings may be used as well. For example, T&D equipment often has what is commonly called an "emergency" rating. That is the sustainable power delivery rate under emergency conditions (*e.g.,* when load exceeds nameplate rating by several percentage points). Operation at emergency rating is assumed to occur infrequently, if ever. See also *Capacity*.

Electrical Subtransmission – Subtransmission transfers smaller amounts of electricity, at lower operating voltages than transmission circuits. In the United States, distribution system operating voltages generally range from several thousand volts to about 200,000 Volts (kiloVolts or kV). For the purposes of this study, "transmission and distribution" is assumed to include subtransmission and not high-capacity/high-voltage transmission systems. See also *Electrical Transmission*.

Electrical Transmission – Electrical transmission is the "backbone" of the electrical grid. Transmission wires, transformers and control systems transfer electricity from supply sources (generation or electricity storage) to utility distribution systems. Relative to electrical distribution systems, the transmission system is used to send large amounts of electricity over relatively long distances. In the United States, transmission system operating voltages generally range from 200 kVto 500 kV. Transmission systems typically transfer the equivalent of 200 to 500 MW of power. Most transmission systems use alternating current, though some larger, longer transmission corridors employ high voltage direct current. See also *Electrical Subtransmission.*

End State – One possible future outcome as defined by a probability tree. Also known as a *Scenario*.

Event – See *Overloading Event*.

Example Case – See *Case*.

Expected Value – The expected value (of a random variable) is the sum of the probability of each possible outcome (scenario) multiplied by each scenario's value. The expected value represents the average value that would be "expected" if a decision with identical odds is made many times. It is important to note that the expected value is not expected in the more general sense; in fact, the expected value may be an unlikely or even impossible outcome.

Excess Demand – Electricity end-user demand (power draw) that exceeds the T&D equipment's design rating for load-carrying capacity. Excess demand is expressed as a) power draw (rate), in units of kW or MW and/or b) a percentage of the T&D equipment's design rating.

Financial Risk – Money-related implications associated with uncertainty. See also *Risk*.

Fixed Charge Rate (FCR) – A value used to convert capital plant installed cost into an annuity or "levelized" equivalent (payment) representing annual carrying charges for capital equipment. The FCR includes consideration of interest and equity return rates, annual interest payments and return of debt principal, dividends and return of equity principal, income taxes and property taxes. The standard assumption value for this report is 0.11.

Genset – Engine generator set that includes an engine, a generator and possibly other equipment needed for genset use. (For this report, gensets are rented and they are powered by a diesel-fueled engine prime mover.)

Hot Spot – An area or node within a utility's T&D system that is known to have challenges related to some combination of a) high demand relative to load carrying capacity, b) unacceptable power quality or c) unacceptable reliability.

Inherent Load Growth – Routine or normal load growth mostly associated with increased business and leisure activities. Inherent load growth is also affected by effectiveness (or lack thereof) of energy efficiency and demand management programs.

Interruptible or Curtailable Load Programs – Utility programs that provide consideration (*e.g.,* discounts) in return for the right to "interrupt" or "curtail" electric energy delivery to specific end-users when the utility is short of energy and/or capacity.

Investor-owned Utility (IOU) – A utility that is owned by investors (stockholders).

Load – Electric power required for operation of electricity-using equipment. Normally load is expressed in kilowatts (kW) or megawatts (MW). See also *Demand*.

Load-carrying Capacity – The amount of load (power draw) that a given portion or element of the T&D system can serve. Units are kiloWatts (kW) or MegaWatts (MW).

Load-duration Curve (LDC) – Hourly demand values (usually for one year), arranged in order of magnitude – regardless of which hour during the year that the demand occurs. Values to the left represent the highest levels of demand during the year and values to the right represent the lowest demand values during the year.

Load Factor – The ratio of the amount of energy that is actually produced, transmitted, distributed or used during a given amount of time (usually a year) to the maximum amount of energy that could have been produced, transmitted, distributed or used during the same time. Example: A 1 MW generator operates for 4,000 hours per year producing 4,000 MW per year. If operated during the entire year, the generator could produce 8,760 MWh. The load factor is 4,000 ÷ 8,760 = 45.7%.

Load Growth – The total increase of peak demand when accounting for both inherent load growth and block load additions.

Locational Marginal Pricing (LMP) – The cost of serving the next MW of load at a specific location when considering marginal cost of generation, transmission congestion related cost, and energy losses.

Marginal Cost – The cost to produce or to procure the next increment (*e.g.*, of energy or capacity). The incremental cost is said to be the cost "on the margin."

Marginal Distribution Capacity Cost (MDCC) – The cost for incremental capacity added to the distribution system.

Maximum Effective Overload – The maximum effective overload that occurs during a year for a given scenario. See also *Effective Overload*.

Maximum Overload – See *Maximum Effective Overload*.

Modular Electricity Storage (MES) – A system that stores and discharges electric energy that can be deployed as several/many individual modules rather than as one or a few large units.

Nameplate Rating – The nominal power delivery rate, for specific equipment, under "design conditions."

Overloading – The condition wherein end-user load exceeds the grid's load-carrying capacity.

Overloading Event – Any circumstance that involves overloading. More specifically, for each scenario, there may be one or more overloading events, depending on the scenario-specific load and the scenario-specific maximum temperature.

Operations and Maintenance (O&M) – Costs incurred to operate and to maintain a specific plant/system. O&M may be fixed (the same for each period without regard to how much a plant/system is used) or variable (varies depending on the amount of use).

Peak Demand – The maximum level of electric power draw during a specified period of time. Daily peak load tends to occur in late afternoon and early evening on weekdays. Annual peaks tend to occur on hot summer days though peak load on some parts of the grid occur during winter when heating-related loads increase.

Peak Load – See *Peak Demand*.

Power Quality – In general terms, power quality (PQ) is defined based on a set of boundaries – such as highest and lowest acceptable voltage or highest acceptable harmonic distortion – that are necessary for electrical systems to function as intended and without significant loss of performance or life.

Probability – The likelihood of a specific future outcome. The chance that a specific scenario will occur.

Probability Distribution – The range and likelihood of possible future outcomes.

Revenue Requirement – For a utility, the amount of annual revenue required to pay carrying charges for capital equipment and to cover expenses including fuel and maintenance. See also *Carrying Charges* and *Fixed Charge Rate*.

Risk – The expected value of a cost (expressed in dollars) given applicable uncertainties and probability distributions associated with those uncertainties.

Risk-adjusted Cost – Total cost for one alternative when summing the direct cost to own and operate the alternative plus the financial risk associated with that alternative.

Scenario – One possible future outcome (or probability tree end state). In the example case, there are 27 scenarios given that there are 3 sources of uncertainty and 3 probabilities assumed for each. Depending on the scenario-specific load and maximum temperature, there may be one or more overloading events for a given scenario. (The 27 Scenarios are shown in Appendix H.)

Subtransmission – See *Electrical Subtransmission*.

System Average Interruption Duration Index (SAIDI) – The duration of sustained interruptions (lasting five minutes or more) experienced by customers of a utility in one year.

System Average Interruption Frequency Index (SAIFI) – The frequency of sustained interruptions (lasting five minutes or more) experienced by customers of a utility in one year.

Transmission – See *Electrical Transmission*.

Transportability – The characteristic of being movable, given practical limits, especially weight and size.

Uncertainty – The state of being unsettled, in doubt, or dependent on chance. Ambiguity, especially about negative implications. A situation for which the result or outcome may only be estimated due to incomplete or imperfect knowledge about the subject addressed.

Unserved Energy – Energy that would be used if it could be delivered and cannot be delivered because of an unplanned interruption of electric service.

Value Proposition – All benefits plus all costs, including risk, that are associated with an investment or purchase.

Volt/VAR control – Combined real time control/management of voltage, reactive power (VAR) and power factor, for optimum performance from an electricity distribution system. Also known as Volt/VAR Control (VVC) or Integrated Volt/VAR Control (IVVC).

Conventions Used in this Report

For simplicity, units of power or load-carrying capacity will be expressed in kilowatts (kW); although, in some cases, kilovolt-amperes (kVA) may be more appropriate. For example, utility equipment is rated in units of kVA rather than kW. For the purpose of this study, the distinction is not important.

The term *transmission and distribution* (T&D) is used throughout this document. It is important to note that the focus of this study is on distribution and subtransmission systems, rather than higher voltage, higher capacity "bulk" transmission systems. Two key reasons for this are: 1) the criteria used to decide whether to add transmission capacity are somewhat different than those used to justify a subtransmission or distribution upgrade and 2) the role for DERs that serves the transmission system directly may be different than the roles served by DERs used for subtransmission and distribution capacity. In this report, the term T&D refers to subtransmission and distribution.

The terms *load* and *demand* are also used interchangeably except for the following: The term "excess demand" is defined as the amount of peak demand that exceeds the rated load-carrying capacity of the T&D equipment; the term "effective overload" reflects that excess demand *plus* effects related to T&D equipment derating due to high ambient temperature.

1. INTRODUCTION

1.1. About this Document

This report addresses the concept of using risk-adjusted cost as the basis for comparing alternatives when the utility needs to add load-carrying capacity (capacity) to the transmission and distribution (T&D) infrastructure.

The need for additional T&D capacity materializes when customer load is approaching the load-carrying capacity of the existing equipment. That need for additional capacity is normally addressed by “lumpy” capacity additions involving additional and/or new equipment whose load-carrying capacity is significantly (25% to 50%) higher than that for the existing equipment.

Two alternatives to such an investment are 1) do nothing or 2) use modular distributed energy resource (DER) alternatives that can be used to provide incremental load-carrying capacity to serve load on the margin, as needed.

> **Introduction to Risk**
>
> Fundamentally, risk is the potential for a specific endeavor or activity to lead to one or more undesirable outcomes. *Financial* risk involves a combination of higher than expected cost and/or lower than expected benefits. A key underpinning of risk is uncertainty about one or more factors that affect the ultimate cost and the ultimate benefit for a given business endeavor.
>
> For example, actual financial returns associated with a business endeavor may involve uncertainty about
> 1) unforeseen costs that may be incurred such as the need for additional equipment or facilities; 2) the future price for “inputs” used for the endeavor such as energy, materials and labor; and
> 3) future demand and allowable price for the endeavor’s output.

1.2. Scope and Purpose

This report describes a framework for comparing traditional and modular alternatives for addressing T&D capacity constraints on a risk-adjusted cost basis. The alternatives compared include a) do nothing, b) do the standard upgrade and c) install one of four modular DER capacity levels and configurations. DERs could include energy storage, generation, load management (*i.e.,* demand response) and geographically-targeted energy efficiency.

This report also provides a high-level characterization of the merits of DER transportability, including increased life-cycle benefits relative to those possible using stationary or permanent systems.

The primary purpose of this report is to characterize the concept of comparing electric utility T&D capacity alternatives based on risk-adjusted cost using a realistic framework and assumptions. The risk-adjusted cost for an alternative is its direct cost *plus* its estimated financial risk.

The objective of such a comparison is to identify the alternative with the lowest risk-adjusted cost for deployment when and where the utility needs additional T&D load-carrying capacity. A secondary purpose is to provide a high-level characterization of the merits of transportable modular energy resources relative to permanent/stationary equipment.

In more general terms, an important objective for this report is to present the concept of risk-adjusted cost comparison as a new way of thinking about T&D capacity expansion involving incremental, “just-in-time” capacity additions and to provide a more explicit characterization of risk associated with T&D investments.

1.3. Premises

The first and most important premise for the concept documented in this report is that there is uncertainty and risk associated with all alternatives that could be used for T&D capacity on the margin. Furthermore, understanding the sources of uncertainty and magnitude of risk allows T&D planners to make superior investment decisions by avoiding some sources of risk and by making prudent responses to other sources of risk. (See Appendix A for an introduction to the concept of risk management, with an emphasis on risk within the electricity marketplace.)

Another important premise is that a portfolio approach to T&D investing – one that includes consideration of direct cost, uncertainty and risk across the utility’s portfolio of possible T&D investments – yields a lower overall cost (of service) borne by utility ratepayers while ensuring that utility investors receive authorized returns.

A third premise for this report is that using modular capacity to serve load on the margin increases the prospects for deriving benefits from DERs that are commensurate with the relatively high cost for most DER alternatives (compared to conventional electric utility alternatives).

The approach described in this report may be especially compelling given the evolution of the electricity marketplace. That evolution is driven by several important factors, especially (and in no particular order):

- Emerging *modular* electric power technologies, particularly distributed generation (DG) and distributed electricity storage (DES)
- Numerous manifestations and components of Smart Grid
- Increasingly powerful analytical tools (*e.g.*, for power engineering and design, capacity planning and financial analysis)
- T&D capacity congestion and T&D upgrade-related constraints
- Increasing emphasis on distribution management systems (DMS) including predictive maintenance protocols, remaining life estimation, and Volt/VAR control
- Increasing uncertainty, about considerations such as environment, fuel price and availability, electric supply sources and cost and changing electricity end-user preferences

1.4. Intended Audience

The audience for this report includes utility distribution planners and engineers, utility finance staff, regulatory and policy stakeholders interested in distributed energy resources (DERs) and/or T&D planning, and DER vendors seeking a richer understanding of the DER value proposition.

1.5. Introduction to Uncertainty and Expected Value

1.5.1. Overview

Perhaps without exception, all human endeavors – including T&D capacity planning – are affected by uncertainty. In basic terms, uncertainty can be described as doubt or ambiguity about a future outcome or result. Uncertainty can come from a variety of sources. A few typical sources of uncertainty for businesses include a) changing demand for a product or service, b) possible shortages of materials used for manufacturing, c) reliability of equipment used to make a product or to deliver a service, d) types and level of expenses that may be incurred when making a product or when providing a service and e) the availability of sufficient capital. To the extent that a source of uncertainty is addressed explicitly, a range of values could be used to reflect the spectrum of possible future values. (Those values are estimated based on some combination of the best available information and sound judgment.)

Consider a utility's peak demand growth, which could be expressed as a spectrum of possible values reflecting low, most likely, and high demand growth. Those values are established after evaluating historic load data and considering likely load additions and overarching economic conditions. As an example: At the low end, demand may grow as little as 0.9% while at the high end, peak demand growth might grow by 2.6%, with the most likely value being 1.72%. For such a range of possible values, there is a distinct likelihood of occurrence (probability) associated with each.

1.5.2. Expected Value

The *expected value* reflects the spectrum of possible future values coupled with the likelihood that each value will occur. It is a composite value that reflects a range of possible future outcomes. Expected value is calculated by multiplying each possible future value by the likelihood (probability of occurrence or just probability) that the value will occur. All of those values are summed to calculate the expected (or probability-weighted-average) value. Table 1 illustrates the expected value calculation for the load growth example situation described above.

Table 1. Simple Example of Expected Value Calculation for Load Growth Rate

Scenario	Load Growth	Probability	Probability-Weighted Value
Low	0.9%	20%	0.18%
Most Likely	1.7%	60%	1.02%
High	2.6%	20%	0.52%
		Expected Value	1.72%

Continuing with the growth rate example just above as an example: T&D planners believe that there is a 60% chance that demand growth will be the most likely rate (1.7%). They also believe that there is a 20% chance of slow growth (0.9%) while the estimated chance that demand will grow more rapidly (2.6%) is also 20%.

1.5.3. Expected Value for Multiple Sources of Uncertainty

In most cases, there is more than one source of uncertainty. Consider an example involving two sources of uncertainty addressed in this report: 1) maximum ambient temperature and 2) load growth.

To evaluate the possible implications of two sources of uncertainty – load growth and maximum ambient temperature as an example – the first step is to combine value and probability data for both of those criteria into a common framework as shown in Table 2.

The values in Table 2 indicate 1) the load growth values shown in Table 1, above, and 2) maximum ambient temperature. From the example: There is a 30% chance that the maximum ambient temperature will not exceed 105°F, a 60% chance that the maximum temperature during the year will be the expected value 107.5°F, while there is a relatively modest 10% probability that the maximum temperature will equal or exceed 110°F.

Table 2. Simple Example of Scenarios Involving Two Sources of Uncertainty

Load Growth Rate (%)			*Maximum Temperature (°F)*			
Case	Rate (%)	Criterion Probability	Case	Temp. (°F)	Criterion Probability	Scenario Probability
Low	0.9%	20.0%	Low	105.0	30.0%	6.0%
	0.9%	20.0%	Most Likely	107.5	60.0%	12.0%
	0.9%	20.0%	High	110.0	10.0%	2.0%
Most Likely	1.7%	60.0%	Low	105.0	30.0%	18.0%
	1.7%	60.0%	Most Likely	107.5	60.0%	36.0%
	1.7%	60.0%	High	110.0	10.0%	6.0%
High	2.6%	20.0%	Low	105.0	30.0%	6.0%
	2.6%	20.0%	Most Likely	107.5	60.0%	12.0%
	2.6%	20.0%	High	110.0	10.0%	2.0%

Also shown in Table 2: 1) there is a 6% chance that load growth and maximum ambient temperature will both be at their lowest respective values, 2) there is a 36% chance that load growth and maximum ambient temperature will both be at or about their most likely values (1.7% load growth and 107.5°F, respectively) and 3) there is a 2.0% probability that load growth and ambient temperature will both be at their respective high values (2.6% load growth and 110°F, respectively).

Note that each line item in Table 2 comprises a *scenario* (one possible circumstance or future condition), also known as an end-state. Note also that the situation shown in Table 2 reflects three values (low, most likely, and high) for two sources of uncertainty (load growth and ambient temperature) so there are 3×3 = 9 value/probability combinations (scenarios) in the example.

1.6. Expected Value and Financial Risk

In simple terms, financial risk involves the money-related implications associated with uncertainty. When evaluating financial risk, after uncertainty has been characterized, the next step is to ascribe financial implications to the scenarios.

As an illustration of how uncertainty and risk are estimated, consider the simplified example in Figure 1. The case and scenarios shown reflect two possible values (high and low) for two sources of uncertainty (load growth and maximum ambient temperature). The results reflect four possible future outcomes (scenarios), each with its own probability and level of overloading. The cost values shown are those associated with overloading that would occur for the respective scenario.

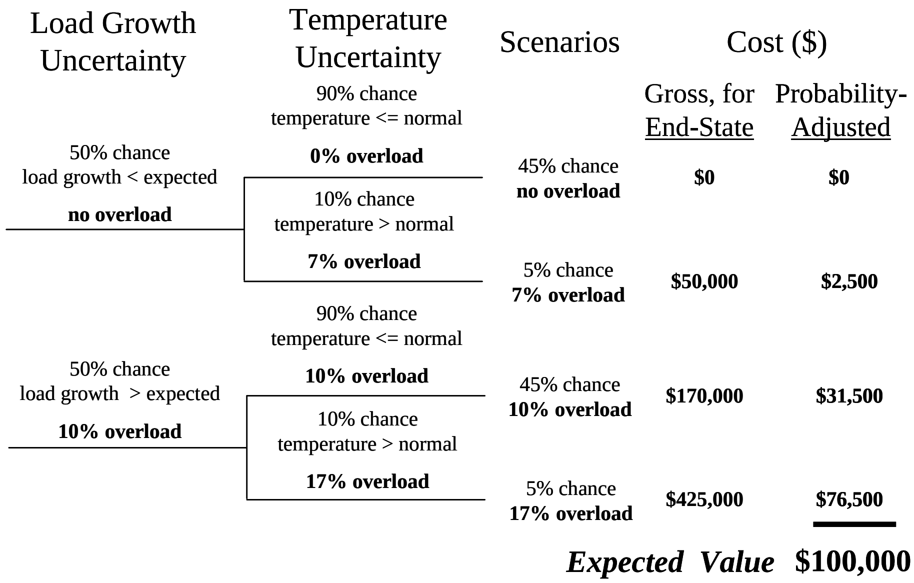


Figure 1. An example of do nothing alternative's expected value.

Figure 1 shows that there is a 50% chance that load growth will be less than projected, causing no overload, and there is a 50% chance that load will be higher than expected, causing a 10% overload.

Regarding temperature-related uncertainty: In any given year there is an assumed one chance in ten that the maximum temperature will exceed the design temperature of the T&D equipment. If that happens, temperature-related overloading is expected to occur. Of course, that means that there is a 90% chance that temperature will not exceed the design temperature.

Finally, the probability-adjusted cost value for each scenario is calculated as follows: the *gross* cost associated with a specific scenario (*i.e.,* each end-state reflecting a specific overloading level) is multiplied by the probability associated with the scenario. Those probability-adjusted cost values are summed to calculate the expected value of cost due to overloading. In the simple example shown in Figure 1, there is a cost (expected value) of $100,000 associated with the do nothing alternative.

1.7. Risk-adjusted Cost Evaluation Framework Scope

1.7.1. Example Case for Assessing Risk

Throughout this report, an example case is used to demonstrate the concepts and techniques characterized. The example is designed to be realistic and to demonstrate key facets of the evaluation.

Qualitatively, the example case reflects a situation for which customer load is about to exceed the load-carrying capacity (capacity) of existing T&D equipment, such that T&D planners expect equipment overloading in the upcoming year.

The evaluation of the example case leads to a comparison of various alternatives that could be used to serve excess load during the next year. The comparison is based on the alternatives' risk-adjusted cost.

The example reflects "summer peaking." That is, the highest demand that the T&D system must serve occurs during the summer when air conditioning (A/C) related demand is highest and when refrigeration equipment operates for a significant portion of the time.

1.7.2. One-year Planning Horizon

The approach used for this report involves evaluating the distribution plan for a *specific* year. Furthermore, the specific year evaluated is what would be the "next" year. Although considerations related to the next year will tend to dominate most final decisions about T&D upgrade investments, failure to consider possible out-year circumstances may result in a suboptimal investment portfolio over time. So it is prudent to consider any year-specific plan in the context of other time periods such as three, five, and ten years.[1]

To do a multi-year risk-adjusted cost evaluation, the single-year analysis documented in this report would have to be undertaken for each year being evaluated and would have to account for the time-value of money. Appendix B includes a discussion of multi-year deferrals.

1.7.3. T&D Capacity Alternatives

The two conventional T&D capacity expansion alternatives evaluated – do nothing and add load-carrying capacity to existing T&D facilities – are compared to various amounts of generic modular distributed energy resources (DERs) located where and when needed.

1.7.4. T&D Planning Uncertainty Sources

Like almost all other business decisions, to one extent or another, uncertainty affects decisions about investments in T&D upgrades. Indeed, an important element of the art of T&D engineering is addressing uncertainty. For this study, the key sources of T&D planning uncertainty addressed are 1) inherent load growth, 2) block load additions or reductions, and 3) weather (temperature). Also addressed are 1) T&D upgrade construction delays, 2) DER reliability, and 3) DER undersizing.

1.7.5. End-user Outage Cost

Normally, a first step in comparing the merits of various T&D alternatives is to establish each alternative's effect on the utility's electric service reliability. Those effects are reconciled with specific reliability metrics used by utilities. Such metrics may be an explicit element of a utility's obligation to serve and/or or they may be based on industry standards. The most familiar indices used as benchmarks for electric service reliability are the System Average Interruption Duration Index (SAIDI) and System Average Interruption Frequency Index (SAIFI). SAIDI and SAIFI are both described in Appendix C. (Ultimately, alternatives that reduce reliability too much are screened out.)

For the evaluation methodology documented herein, perhaps the most significant departure from standard practice is the use of monetized costs that electricity end-users would incur due to service outages (caused by service interruptions and/or poor power quality). Those costs are used to estimate outage-related risk. The amount assumed for end-users' outage-related cost reflects a composite value that is based on an assumed mix of customer classes – each with its own outage-related cost. Related assumptions and calculations used are shown in Appendix C.

Note that outage-related cost is added to the risk as if that risk is incurred by the utility rather than being incurred by end-users.

In reality, utilities will probably not be required to pay for such end-user losses unless the outages are caused by actual utility negligence. Nonetheless, outage-related cost is real and should be part of an inclusive risk-adjusted cost calculus.

1.7.6. Estimating Risk

Risk addressed in this report is directly or indirectly related to T&D equipment overloading. Risk also reflects probabilities associated with specific levels of overloading that would be expected if specific alternatives are used.

The four fundamental elements of risk evaluated for the study are costs associated with 1) T&D equipment damage (damage) due to overloading, 2) utility lost revenue during outages (lost revenue), 3) responding to interruptions (response cost), and 4) customer losses during outages (cost for unserved energy requirements).

Readers should note that risk related to electric supply capacity (generation equipment) and fuels were not addressed for this study. Nevertheless, use of small modular capacity increments may have important risk-related implications for a) generation fuel price and cost, b) the type of electric generation used/added, and possibly c) transmission access and congestion related cost, especially in transmission-constrained regions, d) fossil fuel storage and pipeline infrastructure use and expansion and e) environment-related risk such as increased penalties for pollution/air emissions.

1.7.7. Notable Risk-related Topics Not Addressed

Readers of this report are urged to consider that the authors did not reconcile the concept of T&D risk-adjusted cost and prevailing utility regulations and practices. Typically, utility regulations do not address T&D investment risk fully and/or robustly. Nevertheless, the authors believes that the approach described in this report is somewhat to very compatible with existing regulations and practices. Furthermore, such an approach is becoming more practical given technological advances and changes in the electricity marketplace, such as a) improving means to undertake predictive maintenance and "remaining life" analysis of T&D equipment; b) increasingly sophisticated T&D planning tools; c) the accelerating move to Smart Grid; and d) emerging interest in modular/distributed alternatives to central generation and the grid.

For this study, no consideration was given to potential electrical effects that could be a challenge for DER alternatives, especially reduced (or enhanced) power quality (*e.g.*, voltage stability), service reliability and the normal operation of the existing T&D infrastructure.

Also not addressed are safety-related considerations, especially the potential for electrical islanding. It is presumed that power engineers would undertake appropriate analysis to determine whether a specific case could be addressed safely and reliably with alternatives to conventional T&D capacity expansion.

1.8. Transportable DER Capacity

The topic of transportable DERs is introduced as a complementary topic to risk-adjusted cost because transportable DERs could be an important element of a strategy that includes use of DERs to serve peak demand served by T&D equipment on the margin. Section 5 of this report provides an introduction to the concept, and Appendix B describes a possible framework for assessing the financial merits of multi-year deferrals.

2. OPTIONS

2.1. Introduction

This report addresses the concept of assessing risk related to a T&D investment as a way to optimize the overall cost of delivering electricity to end-users (i.e. delivering the most benefit for a given cost.). A related topic is *options*. Options are important within the context of optimizing risk-adjusted cost because they could be part of the approach used by a utility to achieve the objective. Following is a brief introduction to the concept of options as a way to manage T&D related investment risk. (Detailed coverage of the topic is beyond the scope of this report.)

2.2. Option Contracts

An option contract (an option) is a financial/legal instrument that entails “a promise which meets the requirements for the formation of a contract and limits the promisor's power to revoke an offer.” This type of contract protects an offeree from an offeror's ability to revoke the contract. Typically, an offeree provides “consideration” (*e.g.*, money, reduced obligation to make payment, other assets or services) for the option contract.

In essence, option contacts reflect the price to be paid for the flexibility needed by the utility to address uncertainty and to accept risk in a prudent, explicit and managed way. Thought of another way, options can provide “insurance” against negative outcomes such as insufficient T&D capacity to serve peak demand.

A *call option* is a contract between two parties to exchange something (*e.g.*, asset, product or service, known as “the underlying”), at a specified price (the strike price), by a predetermined date (the expiry or maturity). The owner of the call option has the right but not the obligation to “call” or *buy* the underlying. A put option is the opposite: the owner has the right but not the obligation to “put” or *sell* the underlying by the given date.
The concept characterized in this report resembles a call option owned by the utility because the utility pays for the right but not the obligation to purchase “capacity” from a) an end-user that reduces demand and/or b) another local source of power such as a generator that has been rented or reserved by the utility.

The option price is the amount paid by the utility for the right to buy the capacity. The strike price is amount to be paid for each unit of capacity actually used/purchased by the utility (*i.e., the* price paid for each unit of capacity needed over a specified duration). For demand response, the strike price is the amount paid for each unit of energy not used. For the power source, the strike price is the incremental amount paid to provide the necessary capacity when needed.
The transaction could also resemble a *put option*. Consider an arrangement whereby the utility agrees to sell capacity on-the-margin to an end-user, only if the utility has enough capacity. If the utility is short of capacity, then they are not obligated to sell that capacity to the end-user. Essentially, the utility has a put option on that capacity.

2.3. Real Options

Another possibly attractive way to evaluate prospects associated with use or purchase of real assets is to apply the real options concept. Real options involve the spectrum of ways that real assets could be used. (Examples of real assets include land, plant and machinery.)
Among other attractive features, the real options approach: a) brings to bear the discipline of financial decision-making during evaluation of a company's opportunities, b) links strategy and tactical decisions, and c) improves capital investment planning and results.
Examples of real options include a) do nothing, b) redeploy or modify existing assets, c) rent, lease or purchase additional assets, and d) delayed deployment, or even abandonment, of capital-intensive projects.

A key facet of the real options concept is that real options reflect the often elusive value of flexibility when making decisions in response to changing or unexpected circumstances (uncertainty). More specifically, real options provide managers with a means to increase value by pursuing unexpected opportunities when/if they arise, and/or to manage risk by responding adeptly to uncertainty and changing conditions.

3. RISK ESTIMATION METHODOLOGY AND EXAMPLE CASE

3.1. Introduction

The methodology used for risk estimation and analysis has six primary steps which may be summarized as follows:

1. **Define the Case** – The case is the specific situation or T&D "hot spot" being evaluated. A case is characterized by its location, transformer(s) and/or circuit(s), existing peak load, customer load profiles, weather conditions, *etc*.
2. **Characterize Alternatives** – Identify and characterize the alternatives to be evaluated for the case. For this report, the alternatives considered are 1) do nothing, 2) upgrade existing T&D equipment to serve increasing demand, and 3) add various amounts (of power) from generic distributed energy resources (DERs). This characterization also includes establishing the direct cost of technically viable actual DER alternatives.
3. **Characterize Uncertainty** – Characterize key sources of uncertainty (uncertainties), including the range of possible future values and the related probabilities of occurrence.
4. **Evaluate Overloading** – Estimate 1) the level and frequency of overloading and 2) the cost associated with various levels of T&D equipment overloading that may occur if specific T&D capacity alternatives are used.
5. **Estimate Risk** – Combine a) costs incurred due to various levels of T&D overloading with b) uncertainty, to estimate the potential financial harm associated with use of each T&D capacity alternative being considered.
6. **Compare Risk-adjusted Cost** – Risk for the T&D alternatives considered is added to alternatives' annual direct costs, yielding the single-year, risk-adjusted cost to serve marginal peak demand for each alternative.

These elements are characterized in more detail later in this section.

3.2. The Example Case: Overview

The risk-adjusted cost evaluation characterized in this report involves a specific example case: A utility T&D hot spot requiring some action in the near term (one to two years) to avoid financial harm. The example case is characterized by several key criteria, which are described in more detail later in this section:

- Existing T&D equipment rating
- Existing T&D equipment remaining life and salvage value
- Existing Load – peak demand in the most recent year
- Load Growth – expected values and uncertainty for
  - "inherent" load growth driven mostly by economic conditions
  - "block" load additions (*e.g.,* for new housing developments)
- Expected weather conditions and weather uncertainty

- Upgrade-delay-related uncertainty (*e.g.,* possible sources for delay such as unforeseen budget constraints, staff shortages or permitting requirements)
- Mix of electricity end-user types served (by the T&D equipment of interest) which indicates the composite cost of unserved demand
- Summer peaking (*i.e.,* peak demand occurs during summer)

3.3. T&D Capacity Alternatives

The purpose of the evaluation characterized in this report is to identify the lowest cost alternative for serving peak load on the margin[1] based on risk-adjusted cost, where risk-adjusted cost includes 1) the direct cost to own, rent, or lease the alternative, 2) the direct cost to operate the alternative and 3) the financial risk associated with the alternative.

3.3.1. Conventional Upgrade and Do Nothing Alternatives

One alternative evaluated in this report is the standard utility response: Add capacity to the existing T&D equipment to serve growing load (*i.e.,* upgrade). (Although the T&D upgrade alternative in this report is generic, most T&D capacity upgrades involve additional or larger transformers and circuits.) For the example case, it is assumed that 4,000 kW of load-carrying capacity will be added to the existing equipment rated at 12,000 kW (a 33% increase) for a total of 16,000 kW. The upgrade is needed because load will exceed the load carrying capacity of the existing T&D equipment in one or two years.

Another alternative evaluated is to do nothing. As the name implies, the do nothing alternative would entail a decision to not address the potential need for additional T&D load carrying capacity. Do nothing is a viable alternative if there is reasonable certainty that nothing significantly costly will occur if no T&D upgrade is made.

3.3.2. DER Alternatives

The other class of alternatives evaluated includes various levels of modular distributed electric resources (DERs). One type of DER that could be used includes modular distributed generation (DG). Another is modular distributed electricity storage (DES). Both DG and DES could be owned, leased or rented.

DERs could also include utility programs that lead to a load reduction when and where needed such that a T&D upgrade could be deferred. Examples include geographically targeted energy efficiency (EE) incentives, locational demand response (DR) programs, area-specific critical peak pricing or locational marginal pricing programs, traditional utility interruptible or curtailable load programs, other arrangements between the utility and one or more customers and possibly even arrangements between electricity customers.

[1] The term "on the margin" indicates relatively small quantities (of load) added to the entire amount (peak load). For example, if load is increasing at 1.5% per year, then in a given year, the load added on the margin is 1.5% of the total load.

The four DER alternatives evaluated explicitly in this report are as follows:

1. Use 500 kW of “perfect” (*i.e.*, perfectly reliable) generic DER capacity whose direct cost is assumed to be $100/kW-year.
2. Use 600 kW of perfect generic DER capacity whose assumed direct cost is $100/kW-year.
3. Rent two 250 kW(500 kW total) diesel engine generator sets (gensets), one for the three hottest months of the year and one for the five hottest months of the year.
4. Rent one 250 kW genset for the three hottest months of the year and one 350 kW genset (600 kW total) for the five hottest months of the year.

Note that the concept of perfect DERs is consistent with another important utility concept sometimes referred to as *physical assurance*[2] which can lead to use of modular capacity whose effective reliability approaches 100%, such as demand response. Similarly, if total DER capacity is comprised of “aggregated” capacity from several smaller units – sometimes referred to as a virtual power plant (VPP) – then unit diversity also enhances DER reliability.

3.3.2.1. Electricity Storage Discharge Duration

There is one important difference between energy storage and other types of DERs used to reduce risk-adjusted cost: Storage is often referred to as a “limited energy resource” as it can only store and deliver a given amount of energy. Compare that to 1) fossil-fueled generation whose discharge duration is limited only by the amount of fuel that can be stored on-site and the degree to which fuel can be replenished when needed and 2) demand-side alternatives that tend to target reduced end-user demand (*i.e.,* peak *power* draw).

So, in addition to power rating, storage *discharge duration* is a critical facet of the storage design. Discharge duration is the amount of time that storage can discharge at its nominal rated power output. It is a function of the amount of energy that can be stored. For more detail about storage power and energy requirements, readers are encouraged to refer to a report published by Sandia National Laboratories entitled *Estimating Electricity Storage Power Rating and Discharge Duration for Utility Transmission and Distribution Deferral.*[2]

3.3.3. Alternatives’ Direct Costs

3.3.3.1. T&D Upgrade Direct Cost

The direct cost for the T&D upgrade is defined as the annual utility revenue requirement for the upgrade. That is the amount that utility customers must pay to the utility to cover the utility’s cost to own and operate the upgrade for one year.

[2] This concept is used when “contracting” with electricity end-users who participate in utility programs that allow the utility to either “dispatch” end-user-owned generation or energy storage and/or to reduce or turn off loads as part of a demand management (demand response) program. It involves use of communication and equipment that to limit the power to an end-user when that end-user’s generation, storage or load control does not reduce load (served by the grid) as much as called for under terms of the contract.

For the example case: 4,000 kW of T&D capacity is being added to the existing 12,000 kW of capacity. This is an "upgrade factor" of 4,000 ÷ 12,000 = 0.33. The *incremental* unit cost (cost per unit of capacity *added*) is $210/kW installed, for a total cost of

- 4,000 kW of *capacity added* × $210/kW added = $840,000

or

- $840,000 ÷ 16,000 kW *capacity after upgrade* = $52.50/kW total installed capacity.

A fixed charge rate of 0.11 is used to calculate the upgrade's annual cost (annual financial carrying charges – also known in the utility realm as levelized revenue requirement). The fixed charge rate is a function of a) the mix and cost of (return on) capital (equity/stock and debt/bond) used to purchase and install the equipment, b) return of the capital (like amortization), c) income and property taxes, d) insurance and e) equipment life.

For the example, the annual financial carrying charges (*i.e.*, utility revenue requirements) for the upgrade are

0.11 fixed charge rate × $840,000 total cost = $92,400/kW-year.

(See Appendix E for details about estimating the annual revenue requirement. See Appendix F regarding calculation of T&D upgrade avoided cost.)

Note that T&D operation and maintenance costs (O&M expenses) are assumed to be insignificant enough to be ignored for this report. However, a complete assessment of the revenue requirement would include that cost.

3.3.3.2. Do Nothing Direct Cost

By definition, the direct cost for the do nothing alternative is $0. Although there is no *direct cost* for doing nothing, there is risk. In fact, the only cost for the do nothing alternative is risk.

3.3.3.3. DER Direct Cost

DER direct cost is defined as the cost to own, rent, lease or contract for DER capacity for one year plus the cost to operate the DER for the year.

Figure 2 shows the total annual direct cost – to own and to operate a range of DER capacities – whose direct cost ranges from $75/kW-year to $150/kW-year. To reiterate, these amounts reflect the total ("all in") cost to own, rent or lease, and operate the DER for one year including all fixed costs (*e.g.*, capital carrying cost or rent) and variable costs (*e.g.*, those for fuel and maintenance).

Generator (genset) monthly rental prices (based on published values shown in Appendix G) are $4,455 ($17.82/kW-month) for the 250 kW unit and $6,083 ($17.38/kW-month) for the 350kW unit. Thus, the rental costs incurred (for the example case) for the generators are as follows:

$4,455/month for 250 kW × 3 months = $13,365/year ($53.46/kW-year)

$4,455/month for 250 kW × 5 months = $22,275/year ($89.10/kW-year)

Total: $35,640/year ($71.28/kW-year) and

$4,455/month for 250 kW × 3 months = $13,365/year ($53.46/kW-year)

$6,083/month for 350 kW × 5 months = $30,415/year ($86.90/kW-year)

Total: $43,780/year ($72.97/kW-year)

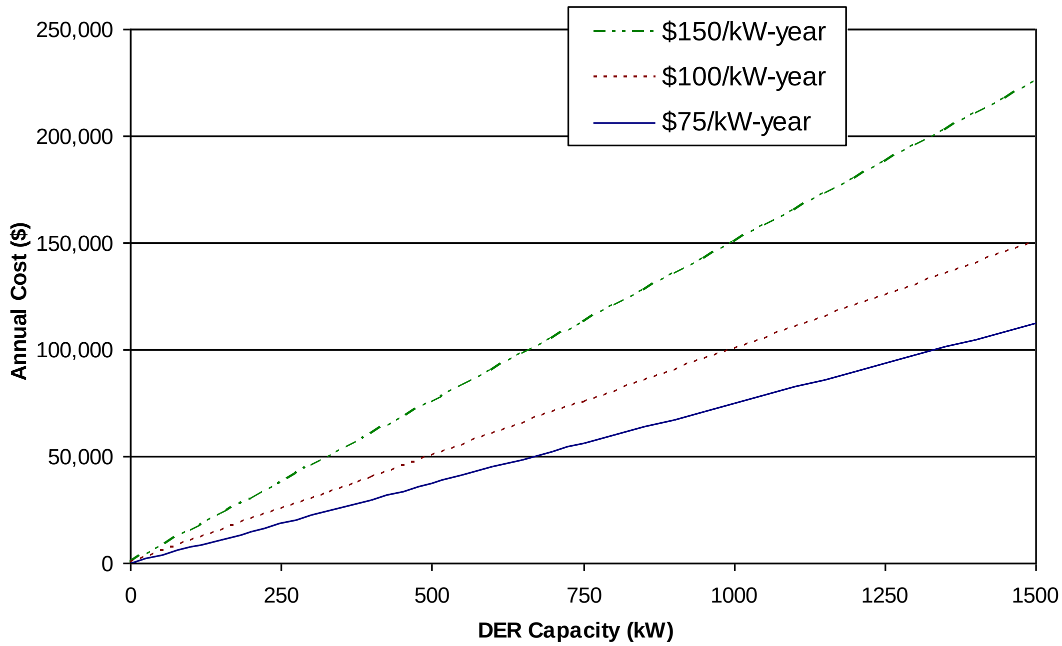


Figure 2. Direct costs associated with various levels of perfect DER capacity.

Fuel price for the rental generators is assumed to be $4.25/gallon. Gensets are assumed to operate at 75% of rated output (0.75 capacity factor) on average leading to a fuel-related cost of about $0.272/kWh.

For two 250 kW gensets operating for a combined 150 hours per year at 75% loading, the total annual fuel cost is $7,650 ($15.30/kW-year). For two gensets – one rated at 250 kW and operating for 80 hours per year and one rated at 350 kW operating for 50 hours per year (at 75% capacity factor) – the annual fuel cost is $7,650 ($12.80/kW-year).

For the two genset rental alternatives evaluated, the total annual cost is 1) $43,290 ($86.60/kW-year) for the two 250 kW gensets and 2) $51,430 ($85.70/kW-year) for the 250 kW plus 350 kW alternative.

For each alternative the assumed annual energy production is 28,125 kWh.

See Appendix G for information and assumptions that form the bases for the direct cost estimates used for the two diesel genset (rental) alternatives.

3.3.3.4. DER Energy and Capacity Value

For the DER alternatives considered, the value of the electric energy generated is treated as if it reduces the net annual *direct* cost for DER (*i.e.*, it is treated as if it is included as a credit in the total DER direct cost for the year, based on the utility's production cost and/or purchase price for the energy). No consideration is given to the need and cost for energy for charging electricity storage, should modular distributed electricity storage be the source of DER capacity. No capacity credit is assumed for the DERs. See Section 3.8.8 for details.

3.4. Uncertainty Affecting T&D Capacity Planning

3.4.1. Load-related Uncertainty

For the example case, three sources of uncertainty (uncertainties) that affect load are addressed: 1) inherent load growth, 2) block load additions, and 3) high ambient temperature. For each of these three uncertainties, there are three values (low, most likely, and high) which yield 27 combinations (loading scenarios). The 27 loading scenarios are shown in tabular form in in Table H-2 in Appendix H. Also shown in Appendix H are the values and probabilities assumed for the three uncertainty criteria and the assumptions about overloading associated with those uncertainties.

3.4.1.1. Inherent Peak Demand Growth Uncertainty

Inherent peak demand growth is the routine (normal) load growth mostly associated with a general increase of existing government, institutional, agricultural, commercial, industrial, and residential demand.

For the example case, probability assumptions about inherent peak demand growth uncertainty for the next year are that there is a

- 20% chance that inherent peak demand growth will be 100 kW (+0.9%)
- 60% chance that inherent peak demand growth will be 200 kW (+1.7%)
- 20% chance of inherent peak demand growth of 300 kW (+2.6%)

3.4.1.2. Block Load Addition Uncertainty

Block load additions are one-time additions involving, for example, new businesses, new housing developments, or a substantial volume of new equipment that adds a large "block" of load relative to the load-carrying capacity of the existing T&D equipment.

For the example case, uncertainty regarding block load additions is characterized as follows: a) there is a 15% chance that no block load will be added, b) there is a 50% likelihood that there will be 250 kW of block load added, and c) the probability of a 500kW block load addition is 35%. See Appendix H for details.

3.4.1.3. Weather Uncertainty

The key weather-related criterion of interest is maximum ambient temperature. At least three temperature-related implications are important. First, high temperature leads to high levels of air conditioning (A/C) and refrigeration use (more equipment operates, increasing power draw and equipment has longer run times increasing related energy use). Second, high ambient temperature reduces A/C equipment efficiency. Third, high temperatures reduce the load-carrying capacity of T&D equipment.

For the example case, uncertainty about the maximum ambient temperature (for the year) is characterized as follows: a) there is a 90% chance that the maximum ambient temperature will not exceed the T&D equipment's "design temperature" of 105°F, b) there is a 7.5% chance that the maximum temperature will be 107.5°F, and c) there is a 2.5% chance that the maximum temperature will be 110ºF or greater.

3.4.2. Construction Delay Uncertainty

Another source of uncertainty that may affect T&D upgrade projects is the potential for construction delays. Delays can have several causes, including: poor weather, permitting and approval delays, insufficient staff and/or equipment, budget constraints, lawsuits, or changing utility priorities. For the example case, it is assumed that there is a 15% chance of a construction delay (such that the upgrade is not completed before the next year's peak demand months).

3.4.3. DER-related Uncertainty

3.4.3.1. DER Undersizing

Given uncertainty about how high demand will be in any given year, there is commensurate uncertainty regarding the adequacy of the DER capacity deployed. So, for DER capacity below about 1,500 kW (12.5% of the existing T&D capacity), there is a chance that the DER will not have enough power to serve peak load, leading to T&D equipment overloading and possibly damage and even electric service outages. DER undersizing assumptions are described in Section 3.7.3.1 and undersizing risk values for various amounts of DER are shown in Figure 5 (in Section 4).

3.4.3.2. DER Reliability

If DER capacity is used as a T&D capacity resource, then there is some chance that the DER will fail to operate as needed to serve peak load on the margin. That challenge could be mitigated by a) using additional emergency or backup DER and/or demand response capacity or b) using DER capacity comprising several or many small units so that unit diversity reduces the chance that a significant portion of DER capacity fails to operate. DER reliability assumptions are described in Section 3.7.3.2.

3.4.4. Uncertainty Not Addressed

Some sources of uncertainty that may affect T&D capacity planning are not addressed explicitly in this report. Notable sources of uncertainty not discussed here include: a) T&D equipment loading history, b) a changed peak load profile, and c) DER fuel availability.

Readers should note that uncertainty related to electric supply capacity and fuel was not addressed in this study, though use of large amounts of DER capacity could eventually play an important role in utilities' electric supply-related risk management.

3.5. T&D Equipment Overloading

All risk evaluated for this study is the result of T&D equipment overloading. Specifically, the risk is that overloading may cause T&D equipment damage and/or electric service outages (outages). Both equipment damage and outages have related financial costs (*i.e.*, they lead to financial harm). Those costs comprise the basis for the financial risk assessed in this report. See Appendix O for more about the effects of overloading on electrical system component (conductor and transformer) life.

3.5.1. T&D Equipment Rating

For the example case, the nameplate rating of the existing T&D equipment to be upgraded is used to assess overloading. In some cases, however, it may be appropriate to use other ratings such as the "emergency" rating or some adjusted rating based on new information or T&D

enhancements. In those situations, the calculations shown in this report would be made using the appropriate adjusted rating. (To some extent, that consideration is addressed by the concept of overloading floor, as described later in this section.)

Note also that the rating reflects design conditions; most important is the maximum ambient temperature (105°F for the example case).

3.5.2. Ambient Temperature: Effect on Overloading

The effect of high ambient temperatures on T&D equipment is included in the assessment. A robust consideration of temperature-related uncertainty may address temperature and relative humidity. For this report, however, the maximum temperature used is assumed to reflect combined effects of relative humidity and temperature on loads.

Ambient temperature affects T&D equipment loading in two important ways. First, high ambient temperatures lead to higher load levels (than planners projected) because more A/C equipment is turned on and there are more frequent and/or longer run-times for A/C and refrigeration equipment. Second, high temperatures reduce the load-carrying capacity of T&D equipment.

3.5.2.1. Ambient Temperature Effect on Demand

As ambient temperature increases, air conditioning and refrigeration use also increases because a) more air conditioning equipment is turned on, b) air conditioning and refrigeration equipment operate for more time, and c) air conditioning and refrigeration equipment operating efficiency drops as ambient temperature increases.

For the example case, the effect that ambient temperature has on customer demand is assumed to be as follows. For maximum ambient temperature equal to the design temperature of 105°F, (90% chance) there is no incremental demand. If ambient temperature is 107.5°F (7.5% chance), then demand is 5% higher than it would be at the design temperature of 105°F. If ambient temperature is 110°F (2.5% chance), then demand is 10% higher than it would be at the design temperature.

3.5.2.2. Ambient Temperature Effect on T&D Load-carrying Capacity

Importantly, T&D equipment is often rated based on performance at a specific maximum (design) temperature – 105°F for the example case. To the extent that ambient temperature exceeds the T&D equipment's design temperature, the equipment's load-carrying capacity is reduced. So, when demand tends to be highest (*e.g.*, during times when outside temperature and air conditioning use are high), the T&D equipment's load-carrying capacity is reduced. That phenomenon leads to an "effective overload" that is greater than the excess demand due to load growth alone.

Regarding the effect that high temperatures have on (derating of) T&D equipment load carrying capacity: For maximum ambient temperature equal to the design temperature there is no derating. At the other end of the spectrum, T&D equipment is derated by 6.5% if the ambient temperature is as high as 110°F. See Appendix J for details about T&D equipment derating.

(Overloading related *damage* – reducing equipment life – is addressed on Section 3.7.1.1 and Appendix K).

3.5.3. T&D Construction Delay: Effect on Overloading

If the utility selects the standard T&D upgrade as the superior solution, there is a chance that construction may not be completed when needed to avoid overloading of the existing T&D equipment. Construction delays can have a variety causes ranging from staff and/or budget shortfalls to permitting delays. Such delays may lead to overloading of the existing T&D equipment. For the example case it is assumed that there is a 15% chance that there will be construction delays such that the capacity cannot be added when needed.

3.5.4. DERs: Effect on Overloading

There is a chance that DER capacity will not perform as needed/expected – potentially leading to overloading. There are several possible reasons that DERs may not perform as needed/expected: 1) all available fuel has been used and/or no fuel is available; 2) permitting-related run-time constraints; 3) the DER is undersized (*i.e.*, peak load is greater than expected); 4) DER equipment fails to operate when needed (*i.e.*, DER reliability); and 5) the DER's power quality may reduce its effectiveness. (See Section 3.7.3.1 for more about how DER undersizing is addressed and Section 3.7.3.2 for more details about DER reliability.)

3.6. Characterizing Overloading

This section provides an overview of the process and criteria used to characterize the magnitude and frequency of overloading. Additional details are provided in Appendix L.

3.6.1. Excess Demand

For this report, the term *excess demand* is used to characterize the amount of actual customer load that exceeds the T&D equipment's design load-carrying capacity (*i.e.*, the equipment's rating at its design temperature). As an example: If the T&D equipment is rated at 12,000 kW (at 105°F), ambient temperature is about 105°F and end-users' actual peak demand is 12,500 kW, then the excess demand is 500 kW (4.16%).

3.6.2. Effective Overload

In this report, the term *effective overload* is used to describe the degree to which loading exceeds the T&D equipment's load-carrying capacity, given 1) the actual power being used (and resulting excess demand, if any) and 2) the reduced load-carrying capacity of T&D equipment due to high ambient temperature (*i.e.*, derating). For example, if excess demand is 1.5% and ambient temperature is 2°F above the equipment's design temperature – thus reducing the T&D equipment's load-carrying capacity by 2.6% – then the effective overload is 4.1%.

Note that for any given scenario it is the *maximum* effective overload that is calculated.

3.6.2.1. Effective Overload Floor and Ceiling

Although each situation is different, two overloading-related assumptions used for this study are as follows:

- Effective Overload Floor (overload floor) – overloading below the effective overload floor is ignored based on the assumption that overloading of less than that amount will result in negligible financial harm. The overload floor is assumed to be 4%.

- Effective Overload Ceiling (overload ceiling) – overloading in excess of the overload ceiling is assumed to result in service outages. The overload ceiling is assumed to be 10%.

To restate: It is assumed that an effective overload of 4% or less results in little or no financial harm (*i.e.*, limited/no equipment damage and no service outages). An effective overload of between 4% and 10% results in T&D equipment damage only. If the effective overload exceeds the T&D equipment's rated capacity by more than 10%, then there will be damage *and* a service outage.

(See Appendix E for details about T&D equipment damage related financials and Appendix K which provides details about loss-of-life due to overloading.)

3.6.3. Maximum Effective Overload

For this report, *maximum effective overload* is defined as the combined effect of 1) actual end-user demand plus 2) reduced T&D equipment load-carrying capacity due to ambient temperatures that exceed the design temperature of the T&D equipment. In most cases, maximum effective overload occurs on the hottest, most humid weekday(s) of the year (for summer peaking loads) – especially if loads served include a significant amount of space cooling and/or refrigeration.

It is important to note that, for a given scenario, there may be several overloading events – some or most of which involve an effective overload that is less than the maximum overload. The subject of overloading *frequency* is addressed in the next subsection.

3.6.4. Overloading Events: Frequency and Duration

In addition to addressing scenarios' overloading *magnitude,* it is also important to evaluate the *frequency and duration* of overloading events. That is, for any given scenario, there may be one or more overloading events during the year. Also note that for scenarios with higher maximum ambient temperature, there will be more overloading events during the year and the duration of those events will be longer.

Ideally, actual data can be used to quantify overload duration and frequency for specific circumstances. For example, in many cases T&D planners have access to meteorological data that provides details about a) the frequency of high temperature events (how often ambient temperature exceeds specific levels within a year) and b) the duration of high ambient temperatures (how long temperature remains above a specific level).

For this report, assumptions about overloading events' duration and frequency are as follows:

- *Overloading Event Duration* – An overloading event is assumed to last for a few minutes if excess demand is modest and if the temperature is not extreme (*e.g.,* excess demand is 5% or less and ambient temperature is 105°F or less). At the other extreme, overloads are assumed to last for up to 3.83 hours if the excess demand and temperature are extreme (*e.g.,* excess demand is >12.5% and the ambient temperature is 110°F). See Appendix L for details about assumptions regarding overload events' duration.

  (Note: The duration of the overloading indicates the number of DER run-hours needed to avoid the overloading.)

- *Overloading Event Frequency* – Robust development of a frequency distribution for overloading events based on actual weather data is beyond the scope of this report. Instead, a realistic frequency distribution is used for the evaluation. The frequency distribution used reflects the following general assumptions. First, overloading event frequency is a function of the maximum effective overload for a scenario; so, there are more overloading events for scenarios with high maximum effective overload. Second, for the most extreme scenario (with overloading) there may be as many as 21 times per year when damage and/or outages occur. See Appendix L for details about assumptions regarding effective overload values and events' frequency.

A simplifying assumption used for the analysis in this report is that overloading *duration* is treated as if its effect on T&D equipment life (*i.e.,* damage) is insignificant when compared to the effects associated with the *magnitude* of the overload.

3.7. The Elements of Risk for Alternatives to the T&D Upgrade

3.7.1. Risk for the Do Nothing Alternative

For the do nothing alternative, risk comprises costs that will be incurred if there is significant overloading of existing T&D equipment. In other words, if no upgrade is made, then there is some chance that load will exceed the existing T&D equipment's load-carrying capacity.

Four overload-related costs are included in the evaluation: 1) T&D equipment damage, 2) utility response cost, 3) utility lost revenue and 4) electricity end-user outage-related costs. Those costs are described in Sections 3.7.1.1 to 3.7.1.4. Those four elements of risk for the do nothing alternative are calculated based on assumptions about the frequency and duration of both overloading and outages that are described in Appendix L.

3.7.1.1. T&D Equipment Damage Cost

T&D damage occurs when there is excessive loading of the T&D equipment. More specifically, damage results in T&D equipment loss-of-life which has a commensurate cost. The magnitude of that damage-related cost is a function of the magnitude and frequency of overloading.

For this report, utility equipment damage due to overloading was calculated assuming 13 years of remaining useful life for the 12,000 kW of existing T&D equipment. It is assumed that the replacement cost for a new version of the existing T&D equipment is $30/kW. So, the total cost to buy new equipment is

12,000 kW × $30/kW = $360,000.

The *annualized* cost to own that equipment is

$360,000 × 0.11 fixed charge rate = $39,600 per year.

So, for the equipment's 13 years of remaining life there is a remaining value of

$39,600 per year × 13 years = $514,800.

More details about equipment life-related considerations are provided in Appendix K.

3.7.1.2. Utility Response Cost

The cost for a utility to respond to outages is handled simplistically. It is assumed that an average of $1,000 in labor and other response-related expenses is incurred for each utility electric service outage incident.

3.7.1.3. Utility Lost Revenue

During electric service outages, the utility does not receive revenue from customers for energy purchases. That lost revenue is, in essence, a cost incurred and is part of the risk related to overloading.

Lost revenues are a function of 1) the prevailing price for electric energy during outages, 2) the total load that would have been served, and 3) the total amount of time during the year when service is interrupted.

For the example case, the prevailing generation cost and/or purchase price incurred by the utility for electric energy during outages is assumed to be $0.15/kWh. That relatively high price was established based on the assumption that outages are most likely to occur when demand is highest and when on-peak electric energy prices prevail.

As an example: If peak demand for the year is estimated to be 12,000 kW, and if there are five outage hours within the year, the lost revenue would be calculated as

$$\$0.15/\text{kWh} \times 5 \text{ hours} = \$0.75 \text{ per kW of peak demand.}$$

The total lost revenue for the year is

$$\$0.75/\text{kW} \times 12{,}000 \text{ kW} = \$9{,}000.$$

3.7.1.4. Electricity End-user Outage-related Cost

For the evaluation methodology documented herein, perhaps the most significant departure from standard practice is to include – as a component of risk – monetized costs that electricity end-users would incur due to service outages. That cost is a function of two important criteria: 1) the cost per unit of "unserved energy" (expressed in $/kWh) and 2) the amount of time during which there are outages (hours per year).

Importantly, though often challenging to estimate precisely, each end-user customer class and even each end-user within a class incurs a specific cost for unserved energy. In some cases, a specific end-user's outage-related cost may even vary depending on the time-of-day when an outage occurs.

The value used in this report for unserved energy cost ($3.60/kWh) is a composite – it is based on an assumed mix of electricity end-user customer classes, each with its own outage-related cost. (Customer classes include residential, commercial, agricultural, industrial, *etc.*) Assumptions and calculations used to establish the cost of unserved energy are shown in Appendix D.

To calculate the composite customer outage-related cost per kW of load, the unserved energy cost is multiplied by the number of outage hours within the year for each scenario. For example, based on the $3.60/kWh unit cost for unserved energy assumed, if electric service outages for a scenario total 5 hours during the year, then the customer's outage-related cost is $18/kW-year.

To calculate the total annual outage-related cost incurred by all end-users, the cost per kW is multiplied by the relevant level of electricity end-users' demand. For the example case, the load affected is assumed to be the maximum demand (power) that is being served when the outage occurs.

Consider an example: The demand is 12,000 kW when an outage occurs. When applying the $3.60/kWh unserved energy cost, the hourly customer outage-related cost is

$3.60/kWh × 12,000 kW = $43,200/hour.

If there are a total of five hours of outages within a year, then the annual total customer outage cost is

5 hours x $43,200/hour = $216,000.

3.7.2. Risk for the Upgrade Alternative

Risk for the upgrade alternative is assumed to be entirely related to possible construction delays such that the upgrade is not completed before the next peak demand season. The cost associated with such a delay is calculated as a portion of the risk for the do nothing alternative. (Recall that risk is a function of the four overloading-related costs: 1) T&D equipment damage, 2) end-user cost during outages due to unserved energy, 3) utility lost revenue during outages, and 4) utility response cost incurred when outages occur.)

For the example case, it is assumed that there is a 15% chance of construction delay. So the delay-related risk for the upgrade alternative is calculated as 0.15 × the scenario-specific risk for the do nothing alternative. For the example case: If the risk for the do nothing alternative is $99,116, then the risk associated with the upgrade (due to the possibility of construction delay, leading to overloading and related costs) is estimated as

0.15 × $99,116 = $14,867.

3.7.2.1. T&D Asset Utilization, Premature T&D Upgrades and T&D Oversizing

Although not addressed explicitly in this report, a potentially significant element of utility-related risk involves prospects for poor T&D asset utilization. Specifically, a T&D asset may be underutilized if 1) an upgrade is made too soon (*i.e.*, before the need actually materializes because demand does not grow as fast as expected or block load additions are delayed) or 2) before the need for the asset is certain (*i.e.*, the upgrade may not be needed at all).

Such underutilization means that the utility will receive little-to-no revenue associated with the capacity added. The key effect is an increase of the utility's total cost of service (per kW of peak load served).

3.7.3. Risk for the DER Alternatives

Risk for the DER alternatives analyzed herein is assumed to be entirely related to the chance that a DER will fail to provide enough power to avoid T&D equipment overloading. The DER may be undersized, or it may not be totally reliable (leading to one or more times when the DER fails to operate when needed). The cost incurred – if the DER is undersized or if the DER is less than 100% reliable – is actually related to cost due to overloading.

3.7.3.1. DER Undersizing

When using a DER to serve load on the margin, there is a chance that the DER will be undersized (*i.e.*, its *power* rating is not sufficient). If the DER is undersized, then there is a possibility of overloading that leads to T&D equipment damage and even electric service outages. (For the example case, unless the DER is very undersized, there is little chance that the undersizing will lead to *outages*).

The cost (*i.e.*, risk) attributable to DER undersizing is estimated as follows. For a given amount of DER capacity, in each scenario the DER capacity is treated as if it reduces the end-users' peak load by an amount equal to the DER's capacity. The result reflects reduced risk (due to reduced likelihood of overloading) relative to risk for the do nothing alternative.

The undersizing risk associated with various amounts of DER capacity is shown in Figure 5 (in Section 4). As shown in that figure, the risk related to undersizing for a perfectly reliable 500 kW DER is $36,531. There is a smaller chance that a perfectly reliable 600 kW DER is undersized, so the risk is lower too, at $28,072.

The preceding characterization addresses undersizing with regard to DER *power*. It is important to note that undersizing risk is also driven by the possibility that the storage will discharge all of its *energy* while power from the system is still needed, such that it cannot reduce loading of the T&D equipment.

3.7.3.2. DER Reliability

DER used to serve load on the margin needs to be reliable. There is a chance (and related risk) that the DER fails to operate when needed. That effect is referred to as DER reliability-related risk.

In this report, DER reliability-related risk is addressed in a simplistic manner. Risk for the do nothing alternative is multiplied by the chance that the DER will fail (1 – reliability). Perfect DERs are treated as if they are 100% reliable. The reliability of the rental gensets is assumed to be 97.5%.

If the risk for the do nothing alternative is estimated to be $99,116 and the reliability of the gensets rented is assumed to be 97.5%, then the DER reliability-related risk is calculated as

$$\$99{,}116 \times (1 - 0.975) = \$2{,}478.$$

3.8. Notable Caveats about the Approach Used for this Report

3.8.1. General Caveats

Readers are encouraged to consider the results for the example case in this context: The purpose of this report is to characterize the *concept* of comparing T&D capacity alternatives using risk-adjusted cost using a realistic framework and assumptions.

An important general caveat is that consideration of DER capacity as an alternative for T&D upgrade deferral is not common practice. Often, power engineering best practices, utility financials, and regulations do not have provisions for utility-deployed DERs for T&D upgrade deferral or for other applications. So, the approach described in this report could be construed as being inconsistent with utilities' obligation to serve under rate base/revenue requirement approaches. Nonetheless, given accelerating technological change and the rapidly evolving electricity marketplace, the prospects for using DER for T&D deferral and/or for other benefits seem to be improving. Furthermore, because the financial returns for regulated, investor-owned utilities (IOUs) are tied to investments in equipment, there is no financial incentive to "avoid" (*i.e.*, defer) investments, even if lower cost alternatives are viable. (See Appendix M for details.)

Although the framework used in this report addresses the most important sources of uncertainty, some of the assumptions and calculations used to estimate risk involved generalizations, simplifying assumptions and engineering judgment. Key reasons for doing so include a) data is not readily available or accessible, b) data is confidential, c) data is too expensive to buy or to locate, gather, and compile within the project scope and budget and/or d) the evaluation tools needed to undertake such a comparison may not exist. Nonetheless, the approach used is sufficient for demonstrating the concept of comparing alternatives for serving peak demand, on the margin, on a risk-adjusted cost basis.

Another general caveat is that implementing the risk-adjusted cost approach may be limited without more sophisticated communication and control protocols, logic, transaction management, and accounting – like those needed for robust demand response and load and distributed resources aggregation programs and for Smart Grid.

3.8.2. Specific Caveats

Given that important assumptions and calculations involved simplifications, generalizations and judgment, readers are urged to identify and use data and calculations that are appropriate and approved for a given circumstance.

Specific caveats are provided for the following interrelated facets of the approach and assumptions used in this report:

- Upgrade cost
- Value of unserved energy
- Outage duration and frequency
- Existing T&D equipment
  - Remaining life and value
  - Loss-of-life due to overloading
  - Derating due to high ambient temperature
- Load-related effect of high temperature
- Overload floor and ceiling
- Probability of upgrade delay
- DER reliability and effects on the grid

3.8.2.1. Upgrade Cost

For the example case, the T&D upgrade incremental cost assumed ($210/kW for 4,000 kW *added*) is intended to represent a relatively expensive upgrade costing $52.5/kW *total installed capacity* (16,000 kW).

In general, the attractiveness of the risk-adjusted comparison approach is higher for T&D upgrades with higher cost. For more about the subjects of T&D upgrade cost and T&D deferral using modular resources, readers are encouraged to refer to a report published by Sandia National Laboratories entitled *Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage*.[3]

3.8.2.2. Value of Unserved Energy

Perhaps the most important specific caveat about the risk-adjusted cost estimation framework documented in this report has to do with the approach used to address the value of unserved energy (*i.e.*, the cost incurred by electricity end-users because electric energy could not be delivered during outages). For the example case a composite value of $3.60/kWh is assumed.

That criterion – the value of unserved energy – is important because a) the way that it is used in this report is a notable departure from common practice and b) it has a significant effect on results. (Note that customer outage costs dominate the risk associated with the do nothing alternative).

It is a significant departure from standard practice because utility T&D planners typically do not have the means or the need to include explicit and/or robust consideration of customers' outage-related costs when assessing the merits of a given T&D investment. Rather, standard reliability metrics may be used. They provide a gross indication of "acceptable" electric service reliability, without differentiating among individual customers and customer classes (each with their own value of service related to outages). So, arguably, those standard reliability metrics may not provide effective means to account for customer outage-related cost.

Presumably, a more formalized approach to establishing the cost incurred by utility customers during outages would involve a) more rigorous derivation of the value (per kWh) for unserved energy for the various customer classes and b) a regulatory preference for more explicit consideration of that criterion when making T&D expansion or upgrade-related decisions. See Appendix C for more about outage costs and service reliability and Appendix D which includes details about the assumptions used to estimate unserved energy cost.

3.8.2.3. Outage Duration and Frequency

Two criteria – outage duration and outage frequency – are notable for at least two reasons. First, they significantly affect the results because they have a significant impact on the amount of unserved energy. The *amount* of unserved energy, in turn, affects the total *value* of (*i.e.*, cost associated with) unserved energy. Second, these two criteria tend to be somewhat to very different for each region and for specific areas/T&D nodes within a given region (described in Appendix L).

Analysts are urged to identify and use circumstance-specific data for those two important criteria that reflect case-specific circumstances.

3.8.2.4. Existing T&D Equipment

Remaining Life and Value

Remaining T&D equipment life and value have a significant influence on the maximum potential damage to existing T&D equipment. The remaining life (for the existing T&D equipment) is used to estimate its remaining value. That remaining value is used to estimate the financial implications of damage to the existing T&D equipment that occurs due to overloading (if the upgrade is not undertaken).

The cost for replacement equipment is also needed to estimate remaining value. In this case, T&D equipment is assumed to have 13 years of remaining life. The remaining value is estimated based on an assumed replacement value of $30/kW for T&D equipment with a 40-year life. (See Appendix K for details.)

Each type of equipment and each circumstance is different, so real values are needed to evaluate actual circumstances.

Loss-of-life Due to Overloading

Another significant driver of the evaluation results (*i.e.*, of risk associated with overloading) is the damage to existing T&D equipment due to overloading. Consider one related criterion – T&D equipment loss-of-life due to overloading. That criterion is characterized in this report using a generic T&D "damage curve." (The damage curve is shown in Appendix K.)

Note that values reflected by the damage curve, while realistic enough to demonstrate the concept of risk-adjusted cost comparisons, were not developed rigorously. Also, it is important to note that T&D equipment loss-of-life due to overloading is different for each type of equipment; though, for simplicity, a single generic damage curve was used in this report (as if the T&D equipment could be treated as a composite).

An important underlying criterion that affects risk related to equipment damage is equipment remaining life. Remaining life indicates the value of the equipment given the remaining service that it could provide. Unfortunately, power engineers and/or distribution capacity planners may not have a precise value for equipment's remaining life. In such cases, estimating the risk associated with equipment loss-of-life will require adept engineering judgment.

Given the foregoing, analysts should identify and use approved and appropriate data for case-specific evaluations of T&D equipment loss-of-life due to overloading.

Derating Due to High Ambient Temperature

Typically, T&D equipment's load-carrying capacity is established using, among other design criteria, a design ambient temperature. At temperatures above the design value, the equipment's load-carrying capacity decreases.

The "derating curve" used in this report to characterize derating for various ambient temperatures, though realistic, is based on generalizations, engineering judgment, and simplification. It may not be suitable for evaluating specific cases. (See Appendix J for the derating curve.)

In this report, derating is combined with customer load to establish the *effective overload.* Consider an example: For a 12,000 kW transformer, if customer demand is 11,900 kW and high ambient temperature reduces a transformer's load-carrying capacity by 5%, then the effective overload (of the transformer) is

$$(11{,}900\text{ kW} + (5\% \times 12{,}000\text{ kW})) - 12{,}000\text{ kW}$$

$$= (11{,}900\text{ kW} + 600\text{ kW}) - 12{,}000\text{ kW}$$

$$= 12{,}500\text{ kW} - 12{,}000\text{ kW} = 500\text{ kW}.$$

For a given scenario in this report, the same maximum temperature and T&D equipment derating are used for all overloading events associated with that scenario. In reality, each overloading event is different and thus may be driven by ambient temperatures and/or excess demand that is less than it is during the "worst" events.

3.8.3. Load-related Effect of High Temperature

An important consideration for this evaluation is the effect of high ambient temperature on utility customer load. Specifically, as temperature increases, air conditioning use (and thus demand served by the utility) increases. That effect is very circumstance-specific. It is driven, to one extent or another, by the amount of air conditioning that is installed and the mix of customer classes. So, data used in this report to characterize that phenomenon, though realistic, is probably not appropriate for evaluating specific cases.

3.8.4. Overload Floor and Ceiling

The overload floor and overload ceiling criteria have a significant effect on the results presented in this report. Overloading below the overload floor (4%) is ignored. Overloading between the overload floor and the overload ceiling (10%) causes damage to the existing T&D equipment. Most importantly: Overloading that exceeds the overload ceiling results in service outages. The cost associated with those outages, especially the value of unserved energy, tends to be the largest component of risk.

The overloading values used in this report were established using engineering judgment. Although they are meant to be realistic, situation-specific values for those criteria may be somewhat or even significantly different. Important factors affecting those values can include T&D equipment type, quality, age and operational history, and the utility's engineering practices and philosophy.

3.8.5. Probability of Upgrade Delay

A somewhat significant driver of the results presented herein is the risk associated with T&D upgrade construction delays. Construction delays are important if they lead to overloads, because capacity is not installed in time for the peak demand season.

One caveat is that upgrade-delay-related risk is estimated using a simplistic approach: The estimated probability of upgrade delay is multiplied by the risk for the do nothing alternative.

Another caveat is that the value assumed for the probability of upgrade project delay (15%) is meant to be generic, although the possible reasons for delay, likelihood of delay, and potential timing and duration of a delay are year-specific and case-specific.

3.8.6. DER Reliability, Effects on the Grid and Other Challenges

Readers should note that the generic DER reliability values used in this report are probably not suitable for specific cases in part because all DERs are different. It is also important to note the simplistic way that DER reliability-related risk is estimated. That risk is calculated as follows: The chance that DER will fail to operate when needed (1 – reliability) is multiplied by the risk for the do nothing alternative.

In this report, no consideration was given to potential challenges related to operating DERs in conjunction with the grid. One important example is reduced power quality. Also not addressed are safety-related considerations such as those related electrical islanding and on-site fuel storage for DG. Also not addressed are air emissions-related constraints associated with some types of distributed generation. Aesthetics and noise can also pose challenges.

3.8.7. DER Operation

Assumptions about how much the DER alternatives might have to be operated, although intended to be realistic, are arbitrary and are included for completeness. For the example case there is only a 16.1% chance that DERs will have to be operated because no overloading exceeds the 4% overloading floor. (See the summary results shown below Table H-2 in Appendix H.)

That consideration is especially important for a) distributed generation because it requires fuel, b) electricity storage that is charged with electricity from the grid and c) any DER with high non-energy variable maintenance cost.

3.8.8. DER Energy and Capacity Credits

For the DER alternatives considered, the value of the electric energy generated by DERs (if any) is treated as if it reduces the net annual *direct* cost for DER (*i.e.*, it is treated as if it is included as a credit in the total DER direct cost for the year, based on the utility's production cost and/or purchase price for the energy).

However, as mentioned above: For the example case it is likely (~84% chance) that the DERs would not have to be operated at all (*i.e.,* if the more extreme conditions considered do not occur). Of course, there is some chance that the DER will have to operate for more than the assumed amount. Therefore, the energy credit (and operation cost) could range from nothing to somewhat more than the values used. Nonetheless, the energy credit is included as a potentially important incremental benefit for using DERs.

It is important to note that if the perfect DERs' capacity is in the form of demand response, then the amount of energy *not* used by end-users would actually be "lost revenue" and, arguably, would increase the cost from the utility's perspective. If the DER is electricity storage, then the energy credit would be net of cost incurred for energy used to charge the storage.
It should also be noted that no credit is taken for the capacity provided by the DERs. Depending on circumstances (*i.e.*, what generation resource is on the margin) a capacity credit could range from nothing to more than $130/kW-year[3].

[3] Consider a generic example: A combustion turbine is the next electric supply resource that would be added to the grid should more electric supply capacity be needed to serve peak demand growth. If that combustion turbine costs $1,200/kW to install and the fixed charge rate for the utility is 0.11 then the annualized capacity value would be $1,200 * 0.11 = $132/kW-year.

4. RISK-ADJUSTED COST COMPARISON RESULTS

This section includes the intermediate and final results for the risk-adjusted cost comparison for the example case. Compared are six possible alternatives that could be used to serve marginal peak load on heavily loaded T&D equipment during the next year:

1. Do Nothing.
2. Upgrade.
3. Deploy 500 kW of perfectly reliable DER.
4. Deploy 600 kW of perfectly reliable DER.
5. Rent one 250 kW diesel generator for five months plus rent an additional 250kW diesel generator for three months (500 kW maximum).
6. Rent one 350 kW diesel generator for five months plus rent an additional 250kW diesel generator for three months (600 kW maximum).

The following results reflect direct cost for the six alternatives evaluated (scenarios are characterized in Section 3.3.3).

4.1. Intermediate Results

4.1.1. Scenarios' Gross Risk

The first intermediate results – shown in Figure 3 – are risk values for each scenario of the do nothing alternative. These values reflect cost related to equipment damage plus outage-related costs resulting from overloading. The scenario-specific risk values shown in Figure 3 range from $0 for scenarios whose maximum effective overload is less than the overload floor (4%), to about $2.77 million for scenarios characterized by high loads and extreme temperatures that lead to overloading beyond the overload ceiling (10%).[4]

[4] Recall that the overload ceiling (10%) is the maximum effective overload that would actually occur before the existing T&D equipment shuts down, leading to an outage. So, it is assumed that effective overloads that are greater than the ceiling cannot actually occur because electric service would be interrupted once the effective overload exceeds the ceiling. Similarly, if load does not exceed the overloading floor (4%), then it is assumed that damage, if any, is negligible and that overloading does not cause outages.

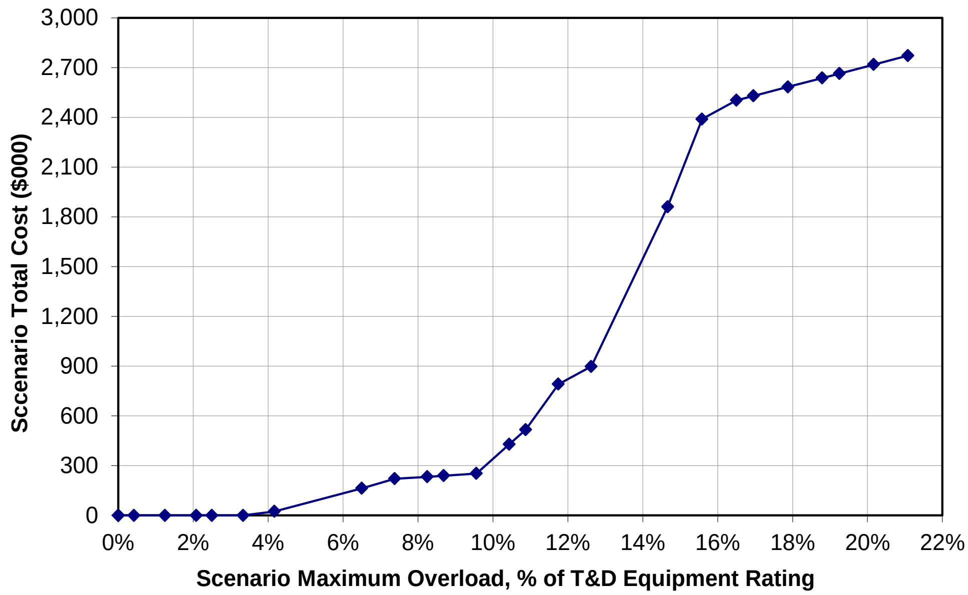


Figure 3. Maximum effective overload-related cost for all 27 scenarios evaluated.

4.1.2. Scenarios' Probability of Occurrence

The scenario-specific maximum effective overload and the respective cost values in Figure 3 are expressed without regard to the probability that a specific scenario will occur. The probabilities associated with scenario-specific maximum effective overload levels are shown in Figure 4.

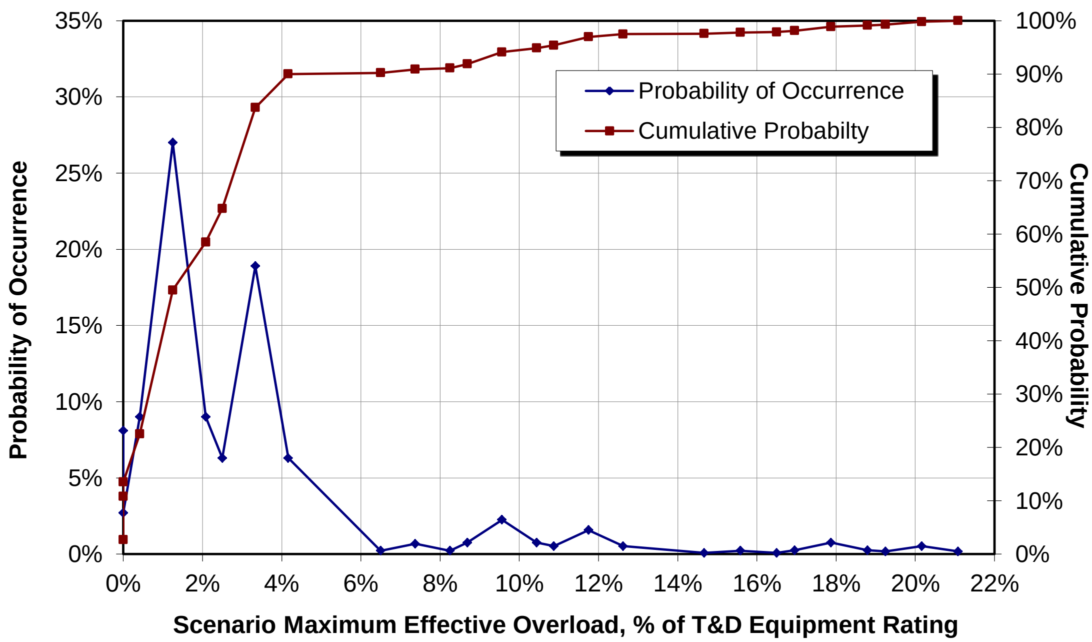


Figure 4. Maximum effective overload and probability of occurrence.

Plotted on the X-axis of Figure 4 are maximum effective overload values for the do nothing alternative, for all 27 scenarios included in the example case. The Y-axis on the left side of the figure indicates the probability of occurrence for each of the 27 maximum effective overload values plotted. (The probabilities associated with each of the 27 scenarios are shown in detail in

Table H-2 in Appendix H). The Y-axis to the right indicates the cumulative probability of occurrence.

Of the 27 scenarios evaluated, there are eight for which the maximum effective overload in the next year would not exceed the overload floor of 4% (*i.e.*, overloading that does not exceed the overload floor will not cause damage to the existing T&D equipment). Those scenarios are plotted on the lower far left quadrant of the figure.

Given the cumulative probability of occurrence (about 84%) associated with those eight scenarios, it is quite likely that that there will not be damage or service outages for the do nothing alternative. Furthermore, because the ninth scenario exceeds the overload floor by a trivial amount, there is an 89.6% chance that overloading will cause little or no damage. Therefore, there is essentially a 90% chance that the DER deployed to serve load on the margin will not be used.

There are six scenarios, with a combined probability of 10.4%, for which the maximum overload is between 4% and 10%, meaning that there is equipment damage but no outages occur.

Figure 4 also shows that there are 13 scenarios, with combined probability of 5.9%, for which the maximum effective overload will exceed the 10% overload ceiling (*i.e.*, service outages will occur), so for those scenarios the cost for damage and outages is high.

Based on the values in Figure 4 (and the values shown in tabular form in Tables N-1 and N-2 in Appendix N), the expected value for the maximum effective overload is 339 kW, or 2.82% of the existing T&D equipment's existing load carrying capacity.

4.1.3. DER-related Risk

4.1.3.1. Undersizing Risk

Figure 5 indicates the undersizing-related risk associated with various levels of DER capacity, for perfectly reliable DERs. To calculate the risk associated with a specific amount of perfectly reliable DER capacity, the DER capacity deployed is treated as if it reduces the peak demand for each scenario by an amount equal to the DER's rated capacity.

The results shown in Figure 5 are derived as follows: Risk is first estimated for the do nothing alternative (*i.e.,* with no DER capacity) as shown in Appendix N. The process described is then repeated for increasing amounts of DER. That is, increasing amounts of DER are assumed then the risk calculation is repeated until the amount of DER added is 1,500 kW.

With the exception of the value for the do nothing alternative, the values in Figure 5 are referred to in this report as those for DER *undersizing* risk. That is, they reflect the expected value of risk associated with a) a given amount of DER capacity and b) the possibility that that amount of DER is not sufficient to avoid overloading of the existing T&D equipment (*i.e.*, overloading may exceed the overloading floor).

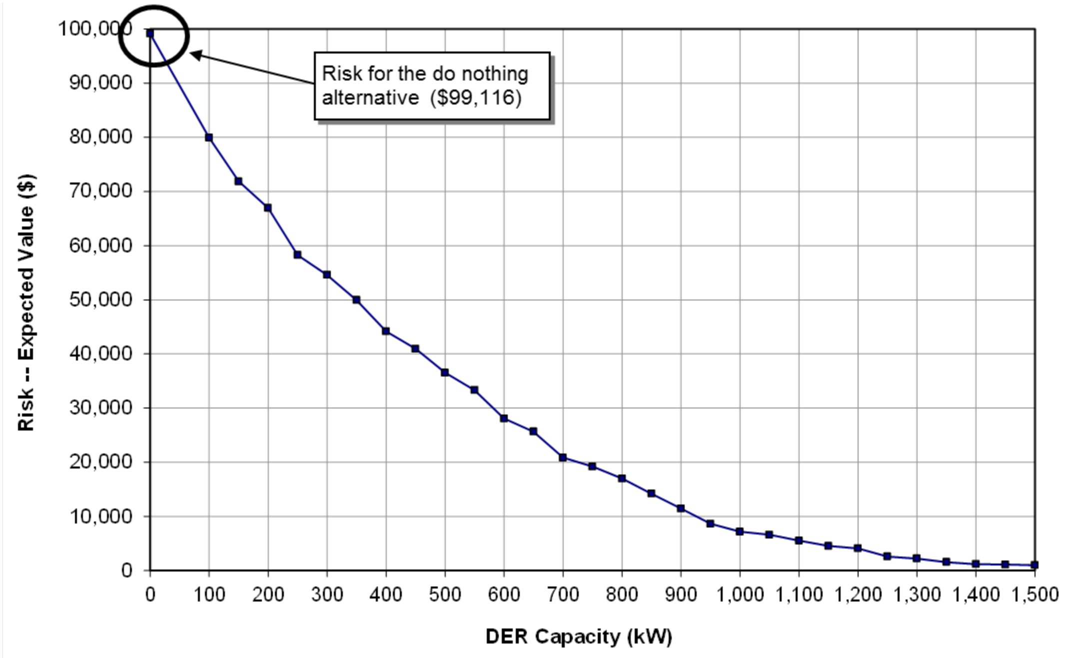


Figure 5. Risk associated with various levels of perfect DER capacity.

In addition to the magnitude of undersizing risk associated with a given level of DER capacity, Figure 5 also shows how risk diminishes as increasing amounts of DER capacity are deployed. See Appendix N for details, including risk calculation examples for the do nothing alternative and for the same situation but with perfect DER capacity rated at 500 kW.

4.1.3.2. DER Reliability-related Risk

DER reliability-related risk is estimated using a simplistic approach: the assumed probability that DER will fail (1-reliability) is multiplied by the risk for the do nothing alternative to estimate the risk. See Section 3.7.3.2 for DER reliability-related assumptions.

4.1.4. Risk-adjusted Costs

Table 3 shows results of combining the values shown in Figure 2 (in Section 3.3.3.3) and Figure 5 just above. The results are also shown graphically in Figure 6. Table 3 shows data for a) the risk for the do nothing approach (which is equal to the total cost estimated for the do nothing alternative), b) the risk-adjusted cost for the T&D upgrade, c) the risk associated with various levels of DER capacity (0 kW to 1,500 kW), d) the annual ownership cost of those various levels of DER capacity, for DERs whose unit cost ranges from $75/kW-year to $150/kW-year and e) the risk-adjusted cost for the various levels of DER capacity and the various DER cost levels considered.

Table 3. Risk-adjusted Costs for Do Nothing, T&D Upgrade and Perfect DERs

Direct Cost and Risk-adjusted Cost

Utility Capacity Alternatives' Risk-adjusted Cost													
Do Nothing ($)	99,116												
Upgrade Cost ($)	107,267												
DER Capacity and Risk													
DER Capacity (kW)	0	100	150	200	250	300	400	500	600	700	800	900	1,000
Risk ($)	99,116	79,926	71,842	66,942	58,246	54,587	44,177	36,531	28,072	20,852	16,996	11,466	7,177
DER Annual Ownership and Operation Cost													
DER Cost $75/kW-year	0	7,500	11,250	15,000	18,750	22,500	30,000	37,500	45,000	52,500	60,000	67,500	75,000
DER Cost $100/kW-year	0	10,000	15,000	20,000	25,000	30,000	40,000	50,000	60,000	70,000	80,000	90,000	100,000
DER Cost $150/kW-year	0	15,000	22,500	30,000	37,500	45,000	60,000	75,000	90,000	105,000	120,000	135,000	150,000
DER Risk Adjusted Cost													
DER Cost $75/kW-year	99,116	87,426	83,092	81,942	76,996	77,087	74,177	74,031	73,072	73,352	76,996	78,966	82,177
DER Cost $100/kW-year	99,116	89,926	86,842	86,942	83,246	84,587	84,177	86,531	88,072	90,852	96,996	101,466	107,177
DER Cost $150/kW-year	99,116	94,926	94,342	96,942	95,746	99,587	104,177	111,531	118,072	125,852	136,996	146,466	157,177

The risk-adjusted costs plotted in Figure 6 are a) the risk for the do nothing approach, b) the risk-adjusted cost for the T&D upgrade, c) the risk-adjusted cost for perfect DERs with a range of sizes and with an annual cost of $75/kW-year, $100/kW-year and $150/kW-year.

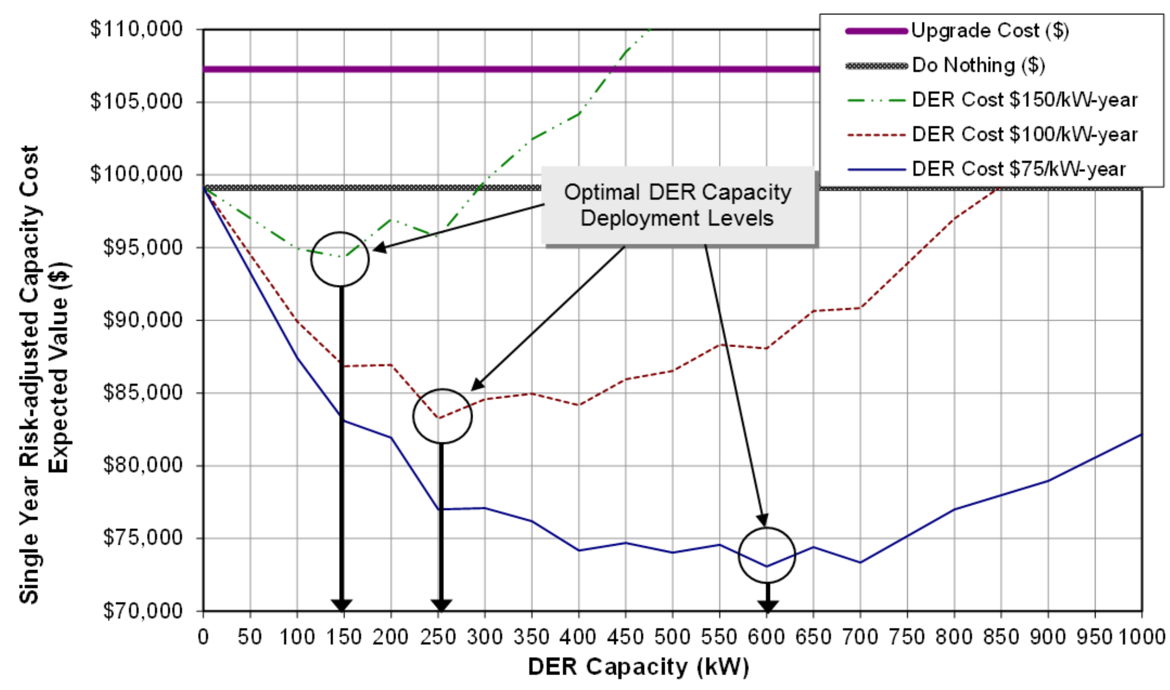


Figure 6. Risk-adjusted costs for do nothing, T&D upgrade and DER.

Based on the results shown in Table 3 and Figure 6, the cost for the do nothing alternative (which is equal to its risk-adjusted cost) is about 4.7% lower than the risk-adjusted cost for the upgrade alternative which is calculated as

$107,267 upgrade risk-adjusted cost – $99,116 do nothing risk = $8,151

$8,151 ÷ $107,267 = 7.6%.

Optimal amounts of perfect DERs costing $75/kW-year, $100/kW-year and $150/kW-year are shown in Figure 6 as minima for the respective plots. Details are as follows.

If perfect DER capacity whose "all-in" direct cost is $150/kW-year then the optimal DER deployment (on a risk-adjusted cost basis) is 150 kW. That DER would have a direct cost of $22,500 for one year and the risk (due to undersizing) is about $71,842. So, for 150 kW of perfect DER costing $150/kW-year, the single-year risk-adjusted cost is about $94,342 – this is somewhat more competitive than the do nothing alternative (whose risk-adjusted cost is $99,116).

For perfect DER's whose annual total direct cost is $100/kW-year, the optimal DER deployment (on a risk-adjusted cost basis) is 250 kW. The direct cost for that DER is $25,000 and the risk due to undersizing is $58,246 for a total risk-adjusted cost of $83,246. By comparison, that is lower than the risk for doing nothing ($99,116) by $15,870 (16%).

Finally, if a perfect DER's annual all-in direct cost is $75/kW-year then the optimal amount of DER is 600 kW. The direct cost is $45,000 per year, the risk related to undersizing is $28,072 for a total risk-adjusted cost of $73,072 for the year. That is lower than the do nothing alternative by $99,116 - $73,072 = $26,044 (about 26.3%).

It is important to reiterate the following: Results shown in Figure 6 are generic in the sense that they are generated without regard to which DER alternatives are actually available. For example, it may not be possible or practical to deploy the optimal amount (600 kW) of DER whose total cost is $75/kW-year. And because the results shown in Figure 6 are for *perfect* DERs, the results do not include consideration of DER reliability.

4.2. Risk-adjusted Cost Comparison Results

The culmination of the evaluation described in this report is a comparison of the alternatives being investigated, on a risk-adjusted cost basis, for the next year of service. Recall that the six alternatives depicted include two "perfect" DERs and four real alternatives are

1. Do nothing.
2. Do the T&D upgrade.
3. Rent one 250 kW diesel genset for the five hottest months of the year and rent one 250 kW diesel genset for the three hottest months of the year (for a total of 500 kW during the three highest demand months). Operate one 250 kW genset for 50 hours at an average capacity factor of 75% (*i.e.*, 75% of rated output) and operate the other 250 kW unit for 100 hours at an average capacity factor of 75%. Reliability is assumed to be 97.5%.
4. Rent one 250 kW diesel genset for the three hottest months of the year and rent one 350 kW diesel genset for the five hottest months of the year (for a total of 600 kW during the three highest demand months). Operate the 250 kW unit for 80 hours at an average capacity factor of 75%, and operate the 350 kW genset for 50 hours at an average capacity factor of 75%. Reliability is assumed to be 97.5%.

4.2.1. Risk for Alternatives

Total risk and the value of the elements of risk for the six alternatives evaluated, for the example case, are shown graphically in Figure 7.

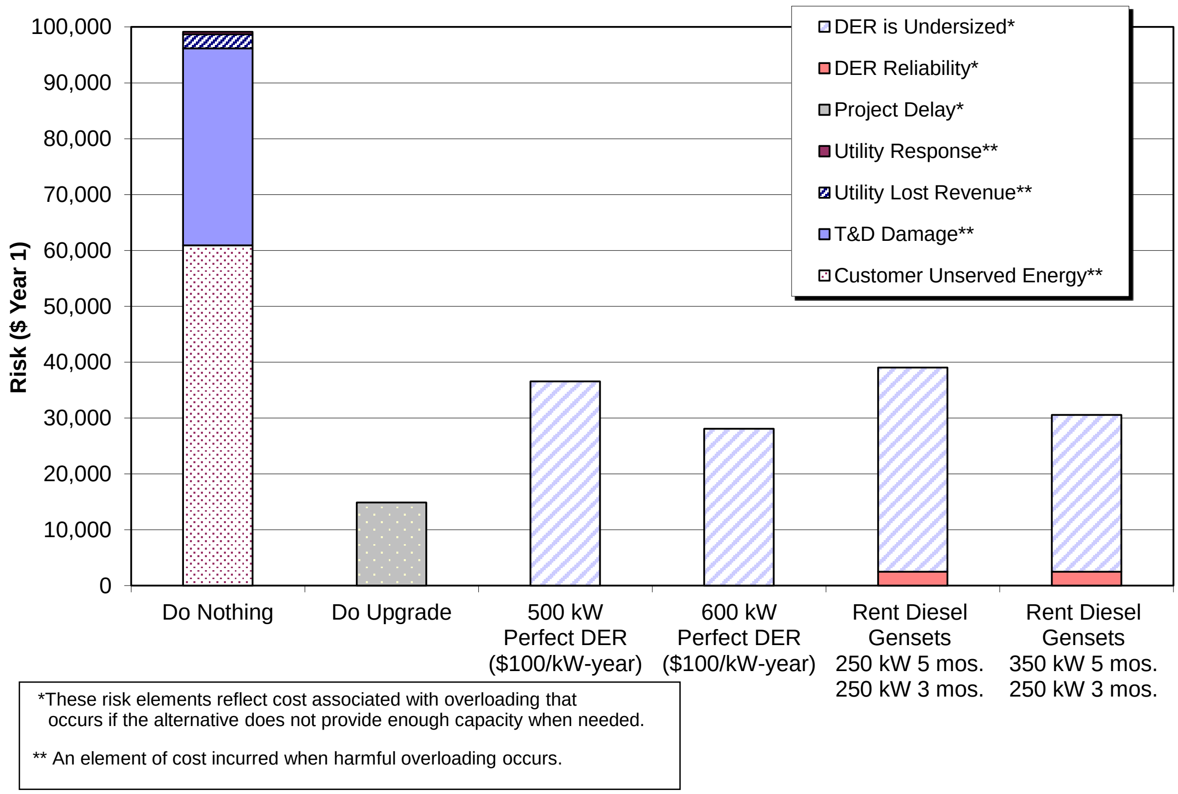


Figure 7. Risk expected values for six T&D capacity alternatives considered.

For the do nothing alternative, the predominant element of risk is cost related to end-user unserved energy. That is, when outages occur, end-users are unable to use electricity normally, for which there is an assumed cost. Also significant is damage to T&D equipment that occurs due to T&D equipment overloading. More modest elements of risk for do nothing are utility lost revenue and response cost incurred when outages occur.

For the upgrade alternative, the entire risk is associated with the chance that the upgrade will not be completed when needed, due to delays, for example, utility capital and/or staff constraints or permitting delays. It is a function of the risk for the do nothing alternative (*i.e.*, it is assumed that there is a 15% chance of delay so the risk is 15% times the do nothing risk.)

DER risk is comprised of two key elements: 1) DER is undersized relative to the maximum load incurred and 2) DER reliability that is less than 100%. (By definition, "perfect" DERs are 100% reliable so there is no reliability-related risk for those alternatives.) Undersizing risk is estimated as described in Section 4.1.3.1. Reliability-related risk is estimated by multiplying 1 minus the reliability for the respective DER times the do nothing risk, as described in Section 4.1.3.2.

4.2.2. Risk-adjusted Cost Comparison

4.2.2.1. Risk-adjusted Gross Cost

Table 4 and Figure 8 show the single-year risk-adjusted gross cost (direct cost *plus* risk) for the six alternatives. The risk portion of the bars in Figure 8 corresponds to (is the sum of) the values shown in Figure 7.

Table 4. Single-year Risk-adjusted Gross Cost Comparison of Alternatives, with DER Operation

	Direct Cost		Risk		Risk-adjusted Gross Cost		Risk-adjusted Gross Cost Relative to *Do Upgrade*		Risk-adjusted Gross Cost Relative to *Do Nothing*	
Alternative	$/year	$/kW-yr	$/year	$/kW-yr	$/year	$/kW-yr	$	%	$	%
Do Nothing	0		99,116		99,116		-8,151	-7.6%	--	--
Do Upgrade	92,400		14,867		107,267		--	--	+8,151	+8.2%
500 kW Perfect DER ($100/kW-year)	50,000	100.0	36,531	73.1	86,531	173.1	-20,736	-19.3%	-12,585	-12.7%
600 kW Perfect DER ($100/kW-year)	60,000	100.0	28,072	46.8	88,072	146.8	-19,196	-17.9%	-11,045	-11.1%
Rent Diesel Gensets 250 kW 5 mos. 250 kW 3 mos.	43,290	86.6	39,009	78.0	82,299	164.6	-24,968	-23.3%	-16,817	-17.0%
Rent Diesel Gensets 350 kW 5 mos. 250 kW 3 mos.	51,430	85.7	30,550	50.9	81,980	136.6	-25,288	-23.6%	-17,137	-17.3%

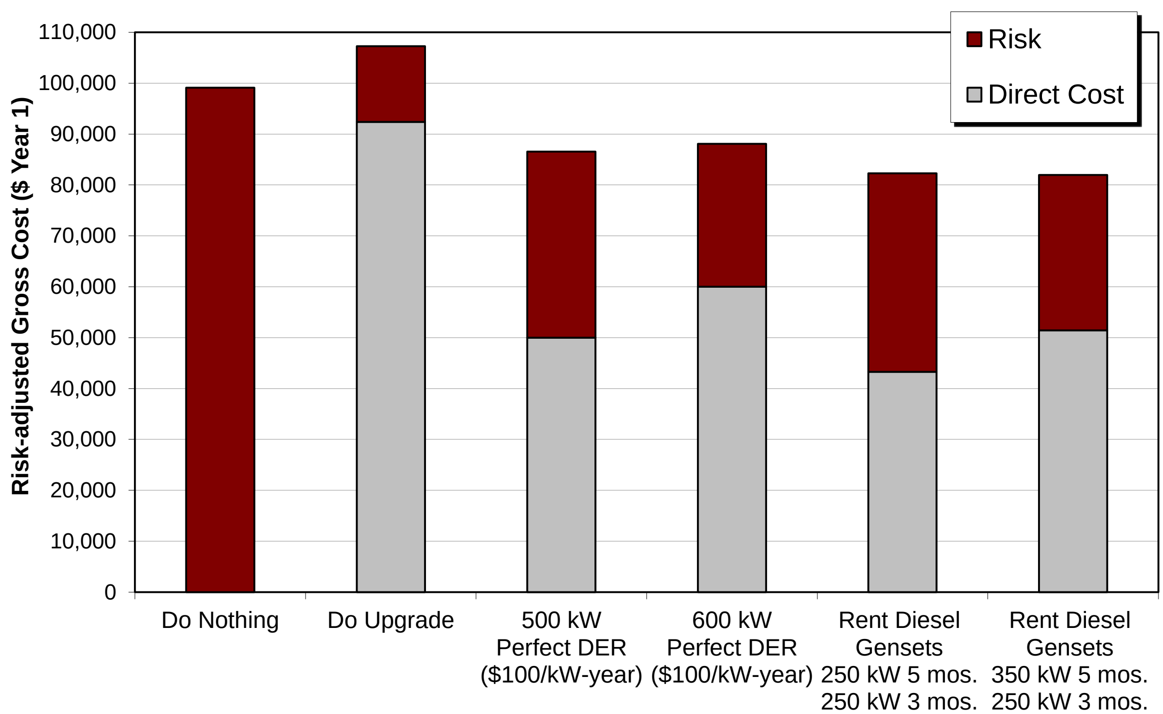


Figure 8. Single-year risk-adjusted gross cost comparison of alternatives, with DER operation.

As shown in Table 4 and Figure 8, the do nothing alternative has a risk-adjusted cost of $99,116, which is lower than the cost for the upgrade by $8,151 (7.6%).

The perfect DER costing $100/kW-year and that is rated at 500 kW has a risk-adjusted gross cost of $86,531. That is $20,736 (19.3%) lower than doing the upgrade and $12,585 (12.7%) less than doing nothing.

The risk-adjusted gross cost for 600 kW of perfect DER (costing $100/kW-year) is $88,072, which is $19,196 (17.9%) lower than the risk-adjusted gross cost for doing the upgrade and $11,045 (11.1%) less than doing nothing.

If renting two 250 kW gensets – one for three months and one for five months – for a total of 500 kW, the risk-adjusted gross cost is $82,299. That is $24,968 (23.3%) lower than the risk-adjusted gross cost for the upgrade and $16,817 (17%) lower than doing nothing.

The lowest cost alternative (on a risk-adjusted gross cost basis) is 250 kW for three months plus 350 kW of rented genset capacity for five months. That alternative's risk-adjusted cost for is $81,980, which is $25,288 (23.6%) lower than the risk-adjusted cost for the upgrade and $17,137 (17.3%) lower than the risk-adjusted cost for the do nothing alternative.
(See Appendix G for details about the gensets' rent, operation hours and energy production.)

4.2.2.2. Risk-adjusted Net Cost

The risk-adjusted cost evaluation culminates with a comparison of alternatives based on risk-adjusted *net* cost. Risk-adjusted net cost reflects risk-adjusted gross cost plus consideration of the value of energy produced by DERs (if any).
The benefit related to the energy produced is referred to as the "energy credit." (Of course, an energy credit only applies if the DERs are actually operated and if the DERs actually produce energy output.) The value for the energy credit assumed and the related assumptions for the four DER alternatives evaluated are shown in Table 5.

Table 5. Energy Credit for DER Alternatives.

	DER Unit 1				DER Unit 2						
Alternative	Power (kW)	Hours	Capacity Factor	Energy (kWh)	Power (kW)	Hours	Capacity Factor	Energy (kWh)	Total Power	Total Energy	Energy Credit*
500 kW Perfect DER ($100/kW-year)	500	75	0.75	28,125	0	0	0	0	500	28,125	-4,219
600 kW Perfect DER ($100/kW-year)	600	62.5	0.75	28,125	0	0	0	0	600	28,125	-4,219
Rent Diesel Gensets 250 kW 5 mos. 250 kW 3 mos.	250	50	0.75	9,375	250	100	0.75	18,750	500	28,125	-4,219
Rent Diesel Gensets 350 kW 5 mos. 250 kW 3 mos.	250	80	0.75	15,000	350	50	0.75	13,125	600	28,125	-4,219

* Energy value is assumed to be 15.0¢/kWh.

As shown in Table 6 and Figure 9 (below): After accounting for the energy credit, the four DER alternatives are even more attractive – relative to both the do nothing and the do upgrade alternatives.

Table 6. Single-year Risk-adjusted Net Cost Comparison of Alternatives, with DER Energy Credit.

	Direct Cost		Credit for Energy*		Net Cost		Risk		Risk-adjusted Net Cost		Risk-adjusted Net Cost Relative to *Do Upgrade*		Risk-adjusted Net Cost Relative to *Do Nothing*	
Alternative	$/year	$/kW-yr	$/year	$/kW-yr	$/year	$/kW-yr	$/year	$/kW-yr	$/year	$/kW-yr	$	%	$	%
Do Nothing	0				0		99,116		99,116		-8,151	-7.6%	--	--
Do Upgrade	92,400				92,400		14,867		107,267		--	--	+8,151	+8.2%
500 kW Perfect DER ($100/kW-year)	50,000	100.0	-4,219	-8.4	45,781	91.6	36,531	73.1	82,313	164.6	-24,955	-23.3%	-16,804	-17.0%
600 kW Perfect DER ($100/kW-year)	60,000	100.0	-4,219	-7.0	55,781	93.0	28,072	46.8	83,853	139.8	-23,415	-21.8%	-15,264	-15.4%
Rent Diesel Gensets 250 kW 5 mos. 250 kW 3 mos.	43,290	86.6	-4,219	-8.4	39,071	78.1	39,009	78.0	78,080	156.2	-29,187	-27.2%	-21,036	-21.2%
Rent Diesel Gensets 350 kW 5 mos. 250 kW 3 mos.	51,430	85.7	-4,219	-7.0	47,211	78.7	30,550	50.9	77,761	129.6	-29,507	-27.5%	-21,356	-21.5%

* Energy value is assumed to be 15.0¢/kWh. Energy produced = 28,125 kWh.

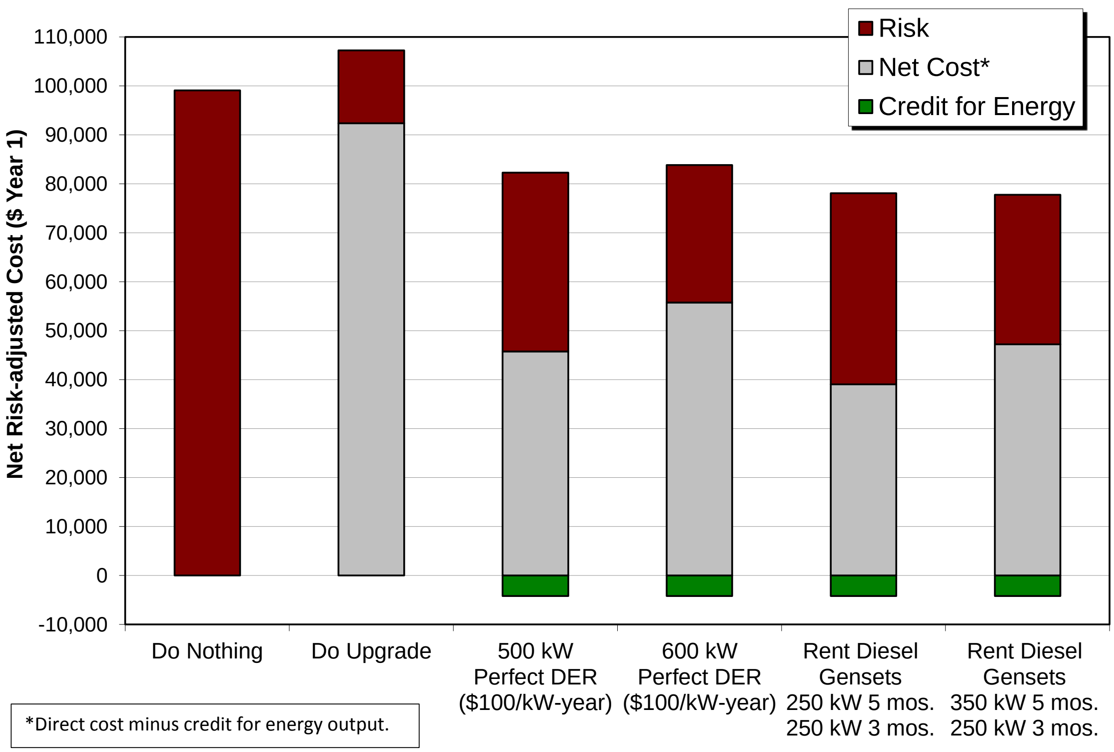


Figure 9. Single-year risk-adjusted net cost comparison of alternatives, with DER energy credit.

When including consideration of the energy credit, the risk-adjusted net cost for 500 kW of perfect DER costing $100/kW-year is $82,313, which is $24,995 (23.3%) lower than the cost for the do upgrade alternative and $16,804 (17%) lower than the cost for doing nothing.
For 600 kW of perfect DER (costing $100/kW-year) the risk-adjusted net cost is $83,853 which is about $23,415 (21.8%) lower than for the upgrade and $15,264 (15.4%) lower than doing nothing.
(Note that if the DER capacity is in the form of demand response, then the amount of energy *not* used by end-users would actually be “lost revenue” to the utility and could result in a net cost

increase (from the utility's perspective). If the DER deployed is electricity storage, then the energy credit would be net of cost incurred to charge the storage.)
Renting one 250 kW diesel genset for three months and another for five months has a risk-adjusted net cost of $78,080 which is $29,187 (27.2%) lower than doing the upgrade and $21,036 (21.2%) lower than doing nothing.

The alternative involving rental of two gensets – 250 kW for three months plus 350 kW for five months – has the lowest risk-adjusted net cost, $77,761, which is about $29,507 (27.5%) lower than doing the upgrade and almost $21,356 (21.5%) lower than doing nothing.
Importantly, there is some chance that the DER will have to operate for more than the assumed amount. So, the energy credit could actually range from nothing to somewhat more than the value used.

It is also important to note that no credit is taken for the capacity (value) provided by the DERs. Depending on circumstances that value could be significant.

4.2.2.3. Risk-adjusted Cost without DER Operation

Recall that (as described in Section 4.1.2) the chance that DERs do not have to be operated is almost 90% (*i.e.*, if the more extreme and unlikely conditions considered do not occur).
Shown in Table 7 and Figure 11 (below) are the results if there is no DER operation required (*i.e.*, no operation cost is incurred and no energy credit applies). In that case, the risk-adjusted cost for the perfect DER is higher because there is no energy credit.

Table 7. Single-year Risk-adjusted Gross Cost Comparison of Alternatives, with No DER Operation

	Direct Cost		Risk		Risk-adjusted Gross Cost		Risk-adjusted Gross Cost Relative to *Do Upgrade*		Risk-adjusted Gross Cost Relative to *Do Nothing*	
Alternative	$/year	$/kW-yr	$/year	$/kW-yr	$/year	$/kW-yr	$	%	$	%
Do Nothing	0		99,116		99,116		-8,151	-7.6%	--	--
Do Upgrade	92,400		14,867		107,267		--	--	+8,151	+8.2%
500 kW Perfect DER ($100/kW-year)	50,000	100.0	36,531	73.1	86,531	173.1	-20,736	-19.3%	-12,585	-12.7%
600 kW Perfect DER ($100/kW-year)	60,000	100.0	28,072	46.8	88,072	146.8	-19,196	-17.9%	-11,045	-11.1%
Rent Diesel Gensets 250 kW 5 mos. 250 kW 3 mos.	35,640	71.3	39,009	78.0	74,649	149.3	-32,618	-30.4%	-24,467	-24.7%
Rent Diesel Gensets 350 kW 5 mos. 250 kW 3 mos.	43,780	73.0	30,550	50.9	74,330	123.9	-32,938	-30.7%	-24,787	-25.0%

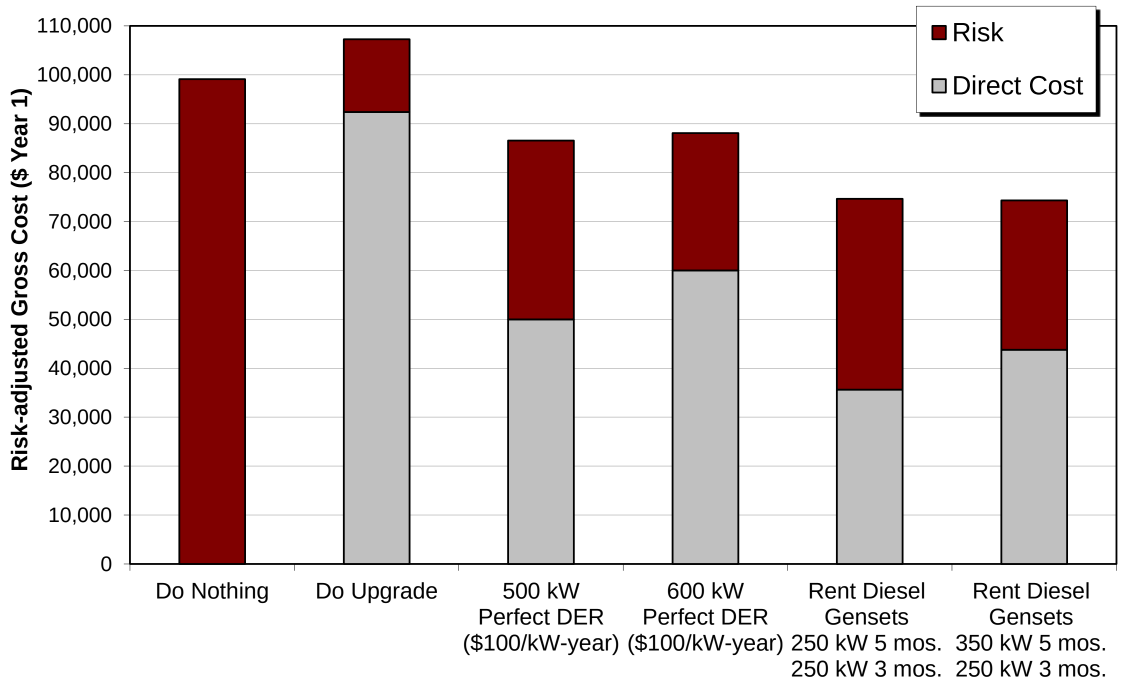


Figure 10. Single-year risk-adjusted net cost comparison of alternatives, with no DER operation.

The risk-adjusted cost for the *gensets* is lower due mostly to reduced fuel-related cost. The first genset rental alternative's direct cost is $35,640 (reflecting rental cost only) and risk-adjusted gross cost is $74,649 which is 30.4% lower than the risk-adjusted gross cost for the upgrade and 24.7% lower than the risk-adjusted gross cost for doing nothing. The second genset rental alternative's direct cost is $43,780 (reflecting rental cost only) while risk-adjusted gross cost is $74,330 which is 30.7% lower than the upgrade and 25% lower than doing nothing. (For details about gensets' cost see Appendix G.)

(Note: results shown in Table 7 and Figure 11 include DER undersizing risk and DER reliability-related risk. Arguably, those elements of risk are not incurred if DER operation is not needed.)

4.2.3. Results' Drivers

What follows are summary listings of criteria and considerations that tend to drive results (that are described above) for a comparison of T&D capacity alternatives based on risk-adjusted cost. Also included are considerations that affect the relative merits of T&D upgrades and DERs used in lieu of T&D upgraded.

Notable T&D-related result drivers and considerations include:

- Load growth uncertainty, especially regarding block loads
- Frequency and duration of outages due to overloading
- Cost for customers' unserved energy needs
- For the existing T&D equipment
    - capacity "headroom" or "slack" remaining

    - useful life remaining
    - replacement cost
- Cost for the T&D upgrade
- Fixed charge rate
- Uncertainty about construction delays
- Temperature variability and maximum
- The overload ceiling and floor values used

DER-related drivers and considerations that can have an important effect on results include:

- DER maturity and familiarity
- DER direct cost including maintenance and fuel cost, if any
- Whether DER is owned by a utility or an end-user
- Whether utility DERs are owned or rented
- DER reliability
- DER flexibility
- Modularity
- Fuel type(s)
- Transportability
- Environmental effects, especially air emissions, noise and visual aesthetics

5. OPTIMIZING CAPACITY RESOURCES USING A FLEET OF TRANSPORTABLE DERS

5.1. Introduction

Given that DERs' tend to have relatively high equipment cost (per kW), some DERs will need to be used several times/at multiple locations to be cost-effective. Conversely, there may be attractive and even significant opportunities for DERs that are readily transportable and (re)deployable (*vis-à-vis* DERs that are stationary).

What follows is a characterization of the concept for using a fleet of transportable DERs (fleet DERs), comprised of modular generation and/or energy storage, to reduce the cost of and/or to improve the quality and/or reliability of electric service.

For this report, a fleet of DERs is defined as follows:

- Two or more readily redeployable DERs – whether owned by the utility, rented or leased by the utility, or provided to the utility under terms of a contract – whose outputs are under the control of the utility.
- The DERs are transportable and sitable without special or onerous permitting or special accommodations that would cause deployment delays of more than a few days.
- Fleet DER unit power ranges from 100 kW to 1 MW.
- For energy storage, discharge duration is 0.25 hours to several hours.

Without regard to cost or other practical considerations, a fleet of distributed generation can include mature technologies such as diesel and spark-ignition engine-driven natural gas fueled generators and other newer technologies such as fuel cells.

Some existing and emerging electricity storage technologies – especially advanced batteries and possibly flywheel energy storage and supercapacitors – may be well-suited to utility fleet DER operations. Several attractive operational characteristics associated with fleet electricity storage include: little or no noise, no direct air emissions associated with combustion, and rapid response to address many short duration electrical phenomena such excessive reactive power and current and voltage spikes and sags.

5.2. Enhancing the DER Value Proposition with Transportability

The fleet DER value proposition is attractive for several reasons. Most obviously, transportable DERs might be used more often than stationary ones. Presuming that additional use leads to more net (lifecycle) benefits, the DER value proposition is enhanced if the DER capacity is transportable.

Consider a possibly compelling example: Fleet DERs could be used to address problems at a summer hot spot and then moved to a winter hot spot in the same year. Redeployable DERs can be used for a wider array of opportunities than stationary DERs, such as providing temporary power or addressing localized temporary or seasonal power quality and/or reliability challenges.

5.2.1. *DERs for T&D Deferral: Diminishing Benefit*

For many hot spots, DERs used *in lieu* of T&D capacity are only viable for one to three years because load eventually grows beyond a level that can be served cost-effectively or reliably by DERs. Once that occurs, transportable DERs could be removed or redeployed.

Consider an example case illustrated in Figure 11 and Figure 12. The case involves the need for an upgrade to equipment at a T&D hot spot. The existing T&D equipment has a rated load-carrying capacity of 12 MW (12,000 kW). The planned T&D upgrade has a total installed cost of $1 million. Using a fixed charge rate of 0.11, the annual cost for the upgrade is $110,000 per year ($1,000,000 × 0.11).

Figure 11 illustrates how the need for capacity on the margin increases due to annual peak demand growth of 2%/year. In Year 1, the local peak demand is not expected to exceed the existing T&D equipment's capacity. Early in Year 1, however, a decision is needed about whether to upgrade for the next year (Year 2) because, as shown in Figure 11, during Year 2 peak demand is expected to exceed the T&D equipment's rated load-carrying capacity by about 0.1 MW (100 kW) or 0.83%.

In Year 3, peak demand growth is expected to be about 0.242 MW (242 kW), leading to load exceeding the existing T&D equipment's rating of about 0.340 MW (340 kW) or 2.83%. In Year 4, peak demand growth is expected to be about 0.247 MW (247 kW), leading to load exceeding the existing T&D equipment's rating of about 0.587 MW (587 kW) or 4.9%. In year 5, the load exceeding T&D equipment rating is a significant portion of the total load, about 7% (0.838 MW or 838 kW).

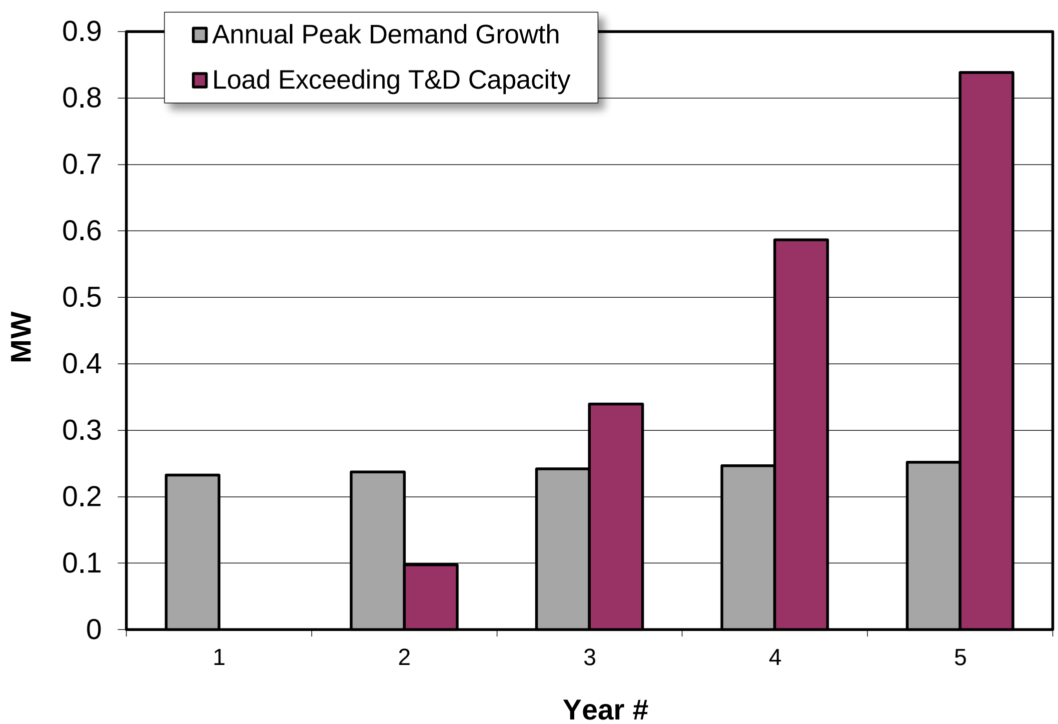


Figure 11. Annual load growth and load exceeding equipment rating.

Figure 12 shows the load exceeding T&D capacity values from Figure 11 as well as a) cumulative DER capacity needed and b) the annual benefit for that amount of DER. DER is assumed to cost $1,000/kW installed and $1,000 * 0.11 = $110/kW-year. DER is “oversized” by 20% to account for uncertainty (*i.e.*, DER power is 20% larger than the projected amount of load exceeding the T&D equipment’s load carrying capacity).

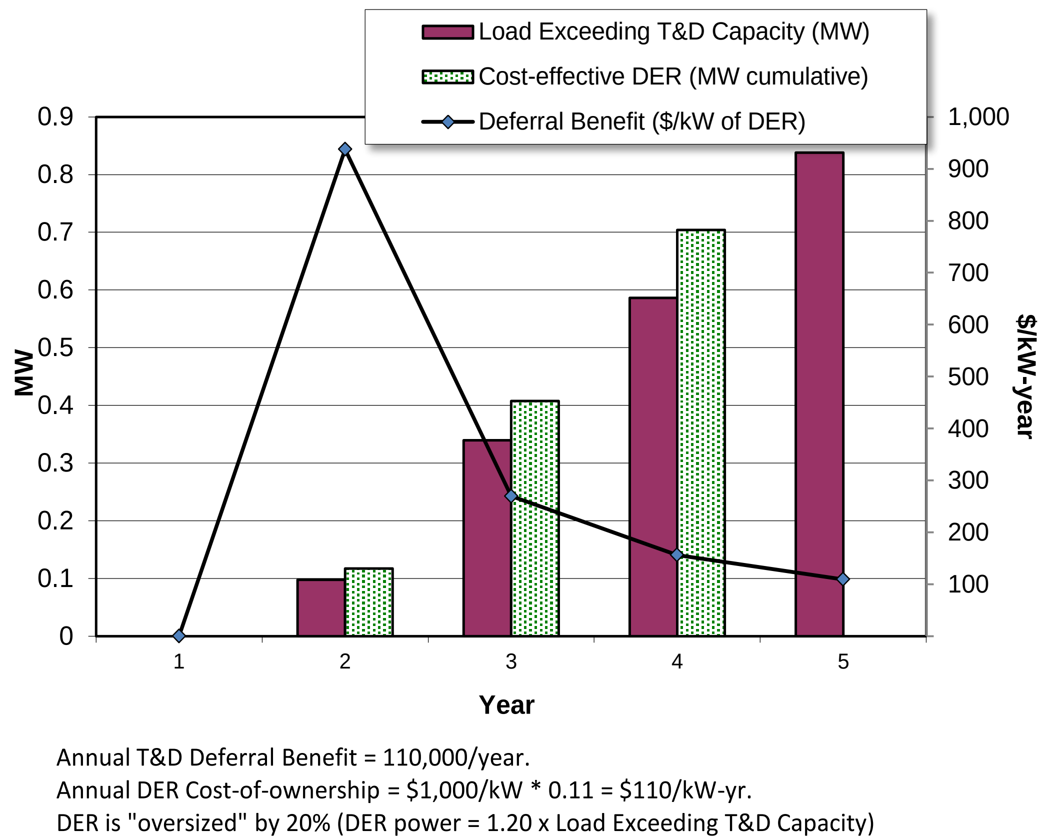


Figure 12. Cost-effective DER capacity and single year deferral benefit.

Year 2 – 117 kW of DER (including 20% oversizing) is needed to serve peak load exceeding the T&D equipment’s load-carrying capacity. The direct cost is $110/kW-year × 117 kW = $12,870 for one year. The deferral benefit for the DER capacity is $110,000 ÷ 117 kW = $937/kW of DER deployed.

Year 3 – An additional 290 kW of DER is needed to serve peak load exceeding the T&D equipment’s load-carrying capacity, for a total of 0.408 MW (408 kW). The direct cost is $110/kW-year × 408 = $44,880W for one year. The deferral benefit for the DER capacity is $110,000 ÷ 408 kW = $270/kW of DER capacity deployed.

Year 4 – An additional 296 kW of DER is needed (including 20% oversizing) to serve peak load exceeding the T&D equipment’s load-carrying capacity. The cumulative amount of DER deployed is 0.704 MW (704 kW). The direct cost is $110/kW-year × 704 kW = $77,440 for one year. The deferral benefit for the DER capacity is $110,000 ÷ 704 kW = $156/kW of DER in place.

Year 5 – So much DER is needed (>1,000 kW) to keep pace with load growth that it is no longer cost-effective to use DER *in lieu* of the T&D upgrade (*i.e.*, DER rated at >1 MW and costing $110/kW has a total direct cost which exceeds the annual carrying cost for the upgrade.)

Note that in addition to needing a growing amount of DER *power*, the number of DER run hours also tends to increase – depending on the load shape. Note also that for the example above, DER cost is escalated to reflect the time value of money.

5.2.2. Transportable DERs for T&D Deferral: Multiple Benefits

A key advantage to using transportable DERs (versus permanent or stationary DERs) to defer a T&D upgrade at a specific location is that when a DER is no longer cost-effective, it can be moved to a different location, to defer another T&D upgrade or for another application (*e.g.*, improving local power quality).

Figure 13 shows the effect for a hypothetical, but realistic, case. In each of ten years, a transportable DER is used either

1. to defer a T&D upgrade, for a benefit of $250/kW of DER in Year 1 dollars

or

2. at a T&D hotspot that has power quality/reliability problems, for a benefit of $75/kW of DER in Year 1 dollars.

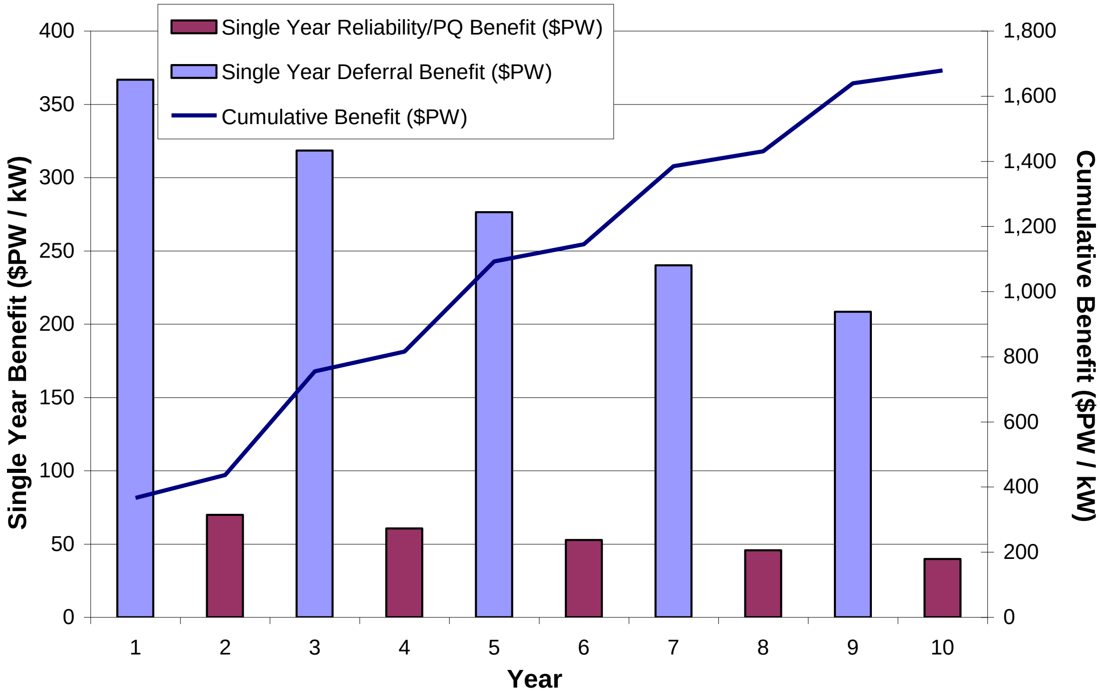


Figure 13. Ten years of benefits from a transportable DER.

5.2.3. *T&D Life Extension*

In the U.S., there is an aging and expensive fleet of underground electric T&D circuits (cables) that will eventually have to be replaced. An emerging opportunity for stationary and transportable DERs is to extend the life of some of those underground cables. Depending on circumstances, utilities could use DERs to serve a portion of the peak load that would otherwise be served by one of those underground cables. The goal would be some combination of a) preventing premature failure of the cable and b) extending the useful life of the cable. The benefit is similar to that for T&D deferral – especially if the cable's operational history is known and/or if the cable's remaining life can be ascertained.

5.2.4. Electrical Support for the Distribution System

Depending on the type of power conditioning equipment used, fleet DERs – especially modular distributed electricity storage (DES) – could be used to address power quality challenges such as unacceptable voltage sags or low power factor. Transportable DES could also be used to damp voltage oscillations that occur when the utility clears a fault (*e.g.,* when a distribution circuit "re-closer" is operated after lightning or when a short causes a fault).

5.2.5. Electric Service Reliability

Transportable DERs could be used to provide constant power in parts of the grid where outages are frequent, such as remote and electrically weak parts of the grid. In those areas, transportable DER capacity could be deployed in such a way that it provides the equivalent of a conventional uninterruptible power supply.

5.2.6. Temporary and Emergency Power

Another use for transportable DERs could be to provide temporary and emergency power that would be impractical with permanent or stationary DERs. This could be especially important given the role that utilities have during disaster response and recovery.

5.2.7. Electric Supply Opportunities

Transportable DERs could also be used for electric-supply or ancillary services related benefits, presuming that doing so will not cause localized technical or temporal conflicts with other uses of the same equipment. For example, a DER that is not in use during summer and that could be connected to the grid could be used to provide on-peak power and energy, spinning or emergency reserve, or transmission congestion relief.

5.2.8. A Utility Fleet of Transportable DERs

A fleet of DERs could be a compelling element of a utility framework involving optimization of risk-adjusted cost for electric service as described in this report. Merely having DERs as an alternative – ready for rapid deployment – may allow utilities to make otherwise risky decisions regarding T&D capacity investments by *managing* risk. To some extent, this philosophy is akin to the concept of just-in-time capacity.

Consider a hot spot for which engineers are somewhat certain that the existing T&D equipment will accommodate one more year's peak load growth. Having the choice to deploy fleet DERs, as needed, might provide the added confidence required so that engineers may delay an upgrade.

Another example is a situation where customer-owned DER capacity is not quite adequate at a specific hot spot. Engineers may be more inclined to accept a somewhat inadequate amount of customer-owned DER capacity if fleet DERs can fill-in when and/or if needed.

Similarly, presuming that the DER fleet includes some reserve capacity, and presuming that a response time of a few hours is acceptable, the fleet's reserve capacity might be a way to increase DERs' effective reliability by providing back-up power. One possibly low cost approach could be to reserve backup generation from local generator rental dealers.

Depending upon elements of the fleet, fleet DERs could be deployed in ways that complement other DERs. An example is the use of fleet generation and storage as a generation-storage hybrid. That approach allows for more stable (and possibly more efficient) electric output, with less air emissions (relative to fleet generation only), while also providing continuous service for many hours, for days, or even weeks (which generation-only or storage-only DERs cannot do).

5.3. Build-out of the Utility Transportable DER Fleet

Ideally, a utility would develop a systematic approach to decide how to undertake an orderly and optimized build-out of transportable DER fleet. The approach would explicitly address the needs that the DER fleet would be used for, to establish the types, number and power rating of DER building blocks in the fleet.

Some important non-cost criteria that might affect the DER fleet build-out include the following (in no particular order):

- The types and diversity of loads and end-users served
- Demand growth rates and uncertainty
- The maximum allowable and/or technically viable portion of demand that can be served by DERs
- The portion of T&D hot spots for which DERs could provide an economically viable alternative
- DER start-up time required and responsiveness to changing conditions
- DER equipment reliability and life expectancy

Somewhat notable is the fact that many utilities are at least partially familiar with fleet management given both their use of vehicles and their need to manage a rotating stock of transformers.[4] Of course, utilities' existing vehicle and transformer fleet management practices and experience are only somewhat transferable to management of a fleet of transportable DERs, given the likelihood that utilities will own a relatively small fleet of DERs relative to the number of vehicles and transformers. Nonetheless, to one extent or another, utilities do have fleet management capabilities.

6. CONCLUSIONS, OPPORTUNITIES AND NEXT STEPS

6.1. Summary Conclusions

Utilities, their customers and society at large would benefit if risk-adjusted cost were used to select the lowest cost T&D capacity alternative to serve marginal load.

For utilities – regardless of whether risk-adjusted cost is considered – use of modular capacity alternatives can improve T&D asset utilization, increase capacity expansion flexibility and lead to lower cost and possibly higher quality service. (Importantly, investor-owned utilities' use of DERs presumes that investor-owned utility stockholders are made whole; meaning that no equity capital goes "unused" and there is no reduction of return on investment. If so, then investor-owned utility stockholders should be indifferent.).

If risk-adjusted cost is used to make decisions about serving load on the margin, then utility customers as a whole will pay less for a given amount of "utility" (*i.e.,* more kWhs and/or additional services can be delivered per dollar spent for each kW of T&D infrastructure).

Furthermore, many interrelated developments in the utility marketplace will drive use of more sophisticated T&D capacity planning and possibly use of new capacity alternatives. Those developments include, among others: a) an expanding spectrum of and increased use of individual DERs, b) growing emphasis on load and DER "aggregation," c) an increasingly "smart" grid, d) increased emphasis on distribution systems management, e) increased emphasis on use of demand response, time-of-use pricing, and locational marginal pricing and f) increasing needs related to renewables integration, especially distributed renewables.

At the T&D level, drivers of more sophisticated capacity planning include a) increasingly detailed and sophisticated SCADA[5], b) increasing availability and quality of historic T&D-related data (*e.g.,* T&D equipment loading history and circuit or transformer loading patterns) which is closely related to c) improving predictive maintenance approaches and remaining life assessments for T&D equipment and d) improving protocols and models for assessing DERs' localized operational impacts and implications (such as effect on impedance and voltage).

Given the foregoing, it seems likely that elements of the risk-adjusted cost evaluation framework described in this report will be used, in one form or another, to one extent or another, for more refined T&D investment decision-making. In fact, the methodology is a) an enhancement of existing T&D capacity planning approaches and b) consistent with increasingly sophisticated T&D evaluation and planning practices, methodologies, and tools such as stochastic modeling.

Prospects may be especially good for use of rented or leased DERs to address T&D investment risk and to limit the risk and challenges associated with utility ownership of DERs. Currently, one of the most cost-effective DERs is modern, clean and very reliable diesel engine generator sets.[5] Given the limited (or no) run hours needed to provide necessary service for T&D peak load reduction: Variable cost (especially fuel) does not contribute significantly to the total cost, and air emissions should not be a significant hurdle in most areas.

[5] The acronym SCADA stands for Supervisory Control and Data Acquisition. SCADA systems collect data from various points within the T&D system which can be used to make decisions about how to manage and control the system and its elements.

Another consideration regarding DER rentals is that rental agencies (primarily for diesel engine gensets) tend to have access to a fleet of units such that rapid deployment of additional capacity is plausible, in many cases, should distribution engineers find that the DER deployed is undersized.

Depending on the circumstances, it may be possible to deploy natural gas fueled DG – rather than the more problematic diesel fueled generation. Specifically, there is a growing array of reciprocating engines, small/micro turbines and "reforming" fuel cells that operate using natural gas fuel. Natural gas is relatively clean, less expensive (per unit of energy) than diesel fuel and in some cases natural gas pipelines may be at or near the location where the DG is needed.

A potentially significant facet of risk related to T&D expansion (investment) is the possibility that T&D capacity added will not be needed until a later date or will not needed at all. In situations where added capacity is not needed until a later date, risk is a function of the annual cost to own the additional equipment and the number of years during which the capacity added is not used or is underutilized. For situations involving upgrades that are never needed, the entire cost to add capacity is at risk. For additional and complementary coverage of the topic, readers are encouraged to consult a paper by Dr. Thomas E. Hoff entitled *Using Distributed Resources to Manage Risks Caused by Demand Uncertainty*.[6]

It seems logical to conclude that some or most DER capacity used for risk management may have to be readily transportable and redeployable. Transportability adds significantly to DERs' potential value because the DERs can be used more (*i.e.*, for several possible applications at a various locations). And, transportability may be especially important during initial phases of DER market development due to high cost per kW for less mature technologies.

One potentially attractive use of a risk-adjusted cost framework would be to address the need to replace an aging fleet of underground circuits in the United States. Given the high expense associated with replacement of those underground circuits (compared to above ground circuits), replacement deferrals that are possible if modular capacity resources are used could also be somewhat to very attractive.

If there is a significant installed base of DERs, they could be an element of electric supply and/or fuel-related risk mitigation, depending on DER types and fuels involved.

Finally, consider that the potential aggregate cost reduction for U.S. utilities that employ the risk-adjusted cost approach could be significant. A newsletter by the Regulatory Assistance Project (aka RAP, raponline.org) states that annual investment in distribution systems is at least $5 billion. If using risk-adjusted costing reduces distribution capacity cost by a mere 10%, then the annual saving would be about $500 million per year.[7]

As an aside: In the same report, RAP also addresses the more general topic of optimizing T&D avoided cost. A RAP newsletter addressing the subject ends with this conclusion:

> *Distribution system economics are likely to have increasing importance to both customers and regulators. It is important to take the opportunity to review this poor "step sister" of the system and assure that we are not investing needlessly in system expansions or improvements. Formalizing that review will help regulators, legislators and customers attain a greater understanding of the issues involved and will enable them to develop appropriate policy objectives and the regulatory tools for achieving them.*

6.2. Richer, More Flexible T&D Capacity Alternatives

One way an approach like that characterized in this report could be implemented is for utilities to have the flexibility needed for T&D risk and reward sharing. Such flexibility, combined with a good understanding of the sources and magnitude of risk, would allow for informed risk management and prudent risk sharing.

An important way that utilities could accomplish risk and reward sharing is to give their customers the financial incentive needed to reduce load and/or to provide power (from customer-owned DERs) as needed. Consider prospects for special rate structures, especially involving location-specific pricing. Or, utilities could provide direct capacity payments to customers for a given amount of load reduction and/or power production, for a specified number of years. Utilities could also target and incent energy efficiency improvements that reduce peak demand where and when needed.

Consider a simple example: A T&D upgrade costs $100,000 per year in carrying costs. The estimated risk for the do nothing alternative is $120,000. The utility pays $30,000 to end-users to reduce load and/or to provide power when and where needed, for one year, such that risk is reduced to $20,000 if the upgrade is not done. In this example, $50,000 is the risk-adjusted cost associated with deferring the upgrade – that is one-half the cost for the utility to own the upgrade for one year.

Another way that utilities could optimize risk-adjusted cost is by contracting for leasing or renting third-party DER capacity such that risk-adjusted cost is less than the cost for an upgrade.

Depending on the circumstances, utilities may even prefer to pay to *reserve* third-party DER capacity that could be deployed if needed (in lieu of actually *renting* the capacity). Such contingency arrangements involving reservation charges would be attractive if they result in lower cost than would be incurred if the DER capacity is actually rented/leased and deployed. (Many rental genset providers can rely on regional or even national fleets of units that could be called upon when needed per reservation terms.)

6.3. R&D Needs and Opportunities

6.3.1. Introduction

The concept of risk-adjusted cost for utility T&D investment optimization (and electric service cost reduction) warrants additional research for at least three primary reasons. First, it seems likely that more robust consideration of T&D-related risk will lead to a more comprehensive valuation of the potential benefits of using modular DERs. Second, regular use of risk-adjusted cost when making T&D capacity related decisions would lead to lower overall T&D capacity cost and thus lower total utility cost-of-service. Third, as the electrical grid becomes more complex, uncertain and dynamic, utility operators and planners will presumably make greater use of stochastic models and evaluation frameworks, rather than relying on approaches that are deterministic and/or that emphasize solutions for the “worst case.”

6.3.2. Next Steps

Based on the relative dearth of data needed to perform risk-adjusted cost evaluations, an important next step would involve characterizing the following: the dataset needed, existing and emerging sources for the data, and expectations about the existence of the data in the future.

Future availability of such data may be driven by the increasing sophistication of utility distribution modeling, monitoring, and forecasting, including use of predictive maintenance and the implementation of Smart Grid, electric vehicles, locational marginal pricing (LMP), demand response and load and DER aggregation.

Another important next step is to evaluate additional cases to better understand the range of possible benefits and the magnitude of the aggregated "portfolio" benefit. Some or all of such cases could be hypothetical, thus it would also be helpful to evaluate some real-life cases. Of special interest are multi-year effects, which may yield significant, compounded savings.

The authors propose to (in collaboration with willing utilities) "build and try" a simple risk-adjusted cost tool – using basic statistical modeling – and to apply that model to actual utility T&D upgrade projects that have already been completed. The insights gained would be used to further assess the merits and viability of the risk-adjusted costing approach and better understand the capabilities needed for a cost-effective, risk-adjusted cost assessment tool.

Given that risk-adjusted costing is not standard practice for electric utility distribution planning, it would be quite helpful to undertake a survey of interested stakeholders to identify challenges and opportunities related to use of risk-adjusted costing. It may be important to establish a more formalized theoretical basis for the risk-adjusted cost concept applying modern finance and regulatory costing theory.

Given modular and transportable DERs' potential as one element of the utility industry's strategy for managing risk related to electric supply, a high-level characterization of the potential for using DERs to manage that risk is timely.

7. References

[1] Chapel, Stephen. Lesser, Jonathan. “Keys to Transmission and Distribution Reliability, a Coordinated Approach Helps Control Costs.” *Public Utilities Fortnightly*. April 2004.

[2] Eyer, Jim. Iannucci, Joe. Butler, Paul. *Estimating Electricity Storage Power Rating and Discharge Duration for Utility Transmission and Distribution Deferral*. Sandia National Laboratory. Report SAND2005-7069. November 2005. http://prod.sandia.gov/techlib/access-control.cgi/2005/057069.pdf

[3] Eyer, Jim. *Electric Utility Transmission and Distribution Upgrade Deferral Benefits from Modular Electricity Storage*. SAND2009-4070. June 2009.

[4] VanZandt, Devin. Walling, Reigh. “DSTAR’s Transformer Cost Analysis Software Enhances Utility Decision Process.” *Utility Automation & Engineering T&D* (Electric Light and Power Magazine). November 2004.

[5] *Rental Charges for Towable Diesel Generators in San Francisco Bay Area*. Sunbelt Rentals. http://www.sunbeltrentals.com/equipment/category.aspx?id=s391. November 8, 2012.

[6] Hoff, Thomas E. *Using Distributed Resources to Manage Risks Caused by Demand Uncertainty*. Clean Power Research (formerly Pacific Energy Group). March 2012. http://cleanpower.com/wp-content/uploads/2012/02/039_DistributedResourcesManageRisks.pdf.

[7] *Focus on Distribution System Regulation: Avoiding Costs and Capturing Values*. The Regulatory Assistance Program Newsletter: Issuesletter. February 2003. http://raponline.org/showpdf.asp?PDF_URL='Pubs/IssueLtr/DistributionSystemReg%2Epdf'.

Appendix A – Introduction to Risk Management

What Risk Is

For the purpose of this study, risk is defined as financial exposure, in the form of potential costs or losses (financial harm), whose magnitude cannot be predicted with certainty. Specifically, risk reflects the financial implications of the range of possible future outcomes, and the range of future outcomes reflects uncertainty about the future. To the extent possible, risk should be expressed in monetary units so that it can be evaluated along with elements of direct cost, such equipment purchase and installation cost.

Types and Sources of Uncertainty

A few typical sources of uncertainty affecting business include the level of future economic activity, the level and types of competition, types and magnitude of costs, and the timing and amount of demand. In addition to those typical sources of business uncertainty, other risk sources affecting the electric utility industry include changing regulations, fuel use and air emissions rules/mandates, permitting and land use constraints, supply and delivery capacity constraints, and future fuel supplies and prices.

Risk Management

In the broadest terms, an organization's risk management process is used to identify, quantify, prioritize, and manage elements of risk as part of its strategy for sustainable performance in competitive markets. The goal is to generate the most benefit for the lowest overall cost, where overall cost includes risk.

Key elements of the risk management process include:

- Policies and procedures
- Common "risk language"
- Risk evaluation tools, techniques and methodology

Once risk has been identified, quantified, and prioritized, it can be managed using a variety of techniques:

- *Accepting* risk as-is
- *Avoiding* risk by eliminating the risky service, product, process, or geographical areas
- *Reducing* risk through policies, procedures, financial activities, or technology
- *Transferring* risk through insurance, contracts, or futures

Other key benefits of an effective risk management process:

- More efficient pricing and expense and capital allocation – with benefits to the organization and society
- Increased competitive advantage (from a more keen awareness of risks and related *opportunities*)

- The organization can be adept at managing existing and new challenges in the evolving electricity marketplace.
- Quantified elements of risk are powerful data to use when seeking management's approval for a specific project, purchase, policy, *etc.*

It is important to note that risk management is not used just to avoid unattractive outcomes. If risk is well understood, it can be used for competitive advantage or to pursue favorable outcomes that may involve taking on risk in an informed, prudent, and measured way.

Consider a simple example: A vendor is reluctant to provide a specialty product with a high margin because it could be liable for "very significant" losses if the product fails due to user error. The vendor decides to characterize the actual magnitude of the risk, rather than continuing to think of it in nebulous terms like very significant. After evaluating the magnitude of the risk, the vendor believes that for a cost that is much lower (than the risk), a user training and support program can be implemented to reduce user error and to reduce risk to a reasonable level. If the vendor is marketing-oriented, it may decide to sell the service to its customers.

Risk and Electric Utilities

For electric utility organizations, most risk (beyond general liability) is financial exposure due to uncertainties related to the economy, shifting customer preferences, market trends, competition, regulation, utility reorganization, institutional challenges such as permits and environmental impact reports, technology (including some that may be effective substitutes for traditional utility service), *etc*.

As with all other enterprises, the utility's total cost to produce and deliver electricity includes costs associated with risk. To some extent, utilities manage risk in some cases quite well (*e.g.*, risk related to fuel purchases for weather-related fuel shortages, demand spikes or major pipeline disruptions). Nevertheless, some types of risk are borne by the ratepayers as a group. Because of the way utility costs are allocated – using the revenue requirements approach – some types of risk are spread among all ratepayers (distributed risk). Although the effect of risk on the overall cost-of-service may seem small when distributed among all ratepayers, risk can be a non-trivial portion of total cost for any particular project, including a) incremental utility infrastructure additions (upgrades) or b) replacement of aging equipment.

Consider an example: Incremental transmission and distribution (T&D) infrastructure additions are made in part based on assumptions about how fast customer peak power requirements (peak demand) will grow and whether or not unexpected block loads materialize. Of course, there is some chance that load will not grow as much as expected and that block load additions will be less than expected.

If that happens, then there is some risk – if the utility decides to add T&D equipment – that the utility will receive less revenue than expected (*i.e.*, the utility will receive fewer dollars of revenue per dollar of investment in the upgrade than expected). So, the effective cost borne by utility ratepayers for the upgrade is higher than expected. Using the revenue requirement approach, utility ratepayers make up that difference by way of a higher price/bill.

Similarly, when considering whether to upgrade heavily loaded equipment, often the do-nothing alternative is chosen based on assumptions about how much customer peak power requirements may grow beyond the existing equipment's rating. Of course, customer demand may grow more than expected. Possible results (risk) may include damage to the existing utility equipment, service outages, and lost utility revenue. In most cases, most or all of the actual cost (risk) is borne by customers. Usually, ratepayers as a whole bear the cost of damage to utility-owned equipment, while customers who are directly affected by a service outage bear the related expenses (*e.g.,* lost productivity, damage to perishables and damage to their equipment).

Risk and Utility Supply and Transmission Systems

To a large extent, risk related to fuel and electric energy supply is addressed robustly by electric utilities. For example, utility fuel purchasing tactics involve hedging and futures, addressing uncertainties like regional weather differences, changing demand patterns and price volatility.

To the extent possible, risk must be quantified, normally in terms of money. Needless to say, some types of risk are difficult to specify in terms of money. For example, a given decision made by a utility might harm the organization's reputation if the decision is a poor one. Such qualitative risk was not addressed in this study.[A1]

Risk and Utility Distribution Systems

A logical extension of risk management for energy supply and transmission capacity is risk management at the distribution level. If nothing else, distribution assets comprise a significant portion of utility capital investment (equipment) and the end-user's bill.

Electricity distribution companies (DISCOs) will face new challenges such as a) integration of distributed resources, including renewables; b) proliferation of Smart Grid and demand response; c) increasing siting-related hurdles; and d) downward pressure on distribution cost. One implication is that DISCO planners may have to take manage and/or take on greater risk, to meet the organization's business objectives and goals. Business objectives could include, for example: low-cost delivery, reliable service, and achieving the authorized return on equity (dividends).

Certainly, DISCOs do evaluate risk by 1) explicitly using an increasing array of tools and techniques and 2) implicitly by applying engineering judgment. Nevertheless, a key element of their strategy for success in the increasingly competitive and diverse electricity marketplace will be to do even more to understand, identify, evaluate, and manage risk.

Risk-adjusted Cost for T&D Expansion Alternatives

In simplest terms, the risk-adjusted cost for a specific alternative is the sum of direct cost *plus* risk. Direct cost comprises the costs to buy or rent and operate a given solution. Direct cost reflects point estimates of future values such as rent and fuel price, without regard to uncertainty. Risk is the alternative-specific expected value of costs or financial losses associated with uncertainty.

The primary purpose of this study is to characterize the concept of using a risk-adjusted cost framework to compare the incremental cost of conventional T&D capacity equipment and distributed energy resources (DERs) on the margin. The comparison indicates the lowest cost way to serve peak demand on the margin, on a risk-adjusted cost basis.

The principal benefit associated with this approach is that it would lead to a lower actual cost-of-service to ratepayers. Secondarily, effective evaluation allows engineers and planners to make smarter, better informed decisions about alternative ways to provide capacity on the margin.

Perspectives on Risk

Four distinct, but interrelated, perspectives on risk are worth noting. As shown in Table A-1, in simple terms 1) energy end-users seek to minimize electricity cost for a given level of utility service, 2) utility power engineers emphasize levels of reliability specified by regulation consistent with the concept of obligation-to-serve, 3) the finance perspective involves maximized risk-adjusted returns for a portfolio of (capital) investments, and 4) the economic or societal perspective involves an optimization of cost – including risk and externalities – for society.

Table A-1. Stakeholder Risk Perspectives

Perspective	Key Criteria	Scope
End-user	Cost (hassle) and/or Profit	Self
Engineering	Reliability (at a reasonable cost)	Project/Facility
Finance	Risk-Adjusted Returns	Portfolio
Macroeconomic	All Costs (including externalities)	Societal

Utility engineering design criteria almost always include a high-level of reliability. Many engineering calculations are based on extreme, but unlikely, conditions that may be encountered. At some point, the cost to achieve marginal reliability improvement exceeds the marginal benefit, even for unique situations where reliability is absolutely critical. In many cases, these assumptions are established using rules-of-thumb, standards, or other guidelines.

Consider weather: To account for weather variability, many engineering calculations are made assuming extreme weather conditions (primarily temperature). For example, the extreme could be defined as the maximum temperature that is expected 95% the time. Such assumptions reflect implicit consideration of risk, where risk involves financial exposure due to the possibility that a design is inadequate. That exposure could include, for example, costs related to utility equipment overloading such as 1) equipment damage/loss-of-life, 2) premature equipment repairs or replacement, and 3) labor costs related to responding to outages.

The contrast between the engineering and finance perspectives is notable. For the most part, engineers seek to minimize risk for a given project, whereas the finance perspective addresses risk across a portfolio of projects.

The macroeconomic or societal perspective involves an optimization among all stakeholders and their respective decision criteria, such as end-user cost, utility service reliability, a portfolio's risk adjusted return, and externalities. The societal perspective is used for this report. Consider an example from this report: Two primary costs addressed here are T&D equipment damage (a cost incurred by the utility) and cost incurred by electricity end-users if electric service is interrupted. While, to some extent, institutional hurdles make optimization at the societal level challenging, it is often helpful to begin with the broader perspective when evaluating DER-related opportunities. The societal perspective allows for a comparison of alternatives on a basis that reflects all costs borne by the key stakeholders: electricity end-users, the utility, and society.

References

[A1] *Derivatives and Risk Management in the Petroleum, Natural Gas and Electricity Industries.* Energy Information Administration, U.S. Department of Energy. Report # SR/SMG/2002-01. October 2002.

Appendix B – A Possible Framework for Assessing Multi-year T&D Deferral Financials

The following methodology for assessing multi-year transmission and distribution (T&D) deferrals was developed by Joe Iannucci, Founder of Distributed Utility Associates.

Purpose

Develop a model that indicates how much distributed energy resource (DER) capacity could be cost-effectively adopted – to defer an expensive distribution planning area (DPA) expansion – before it becomes more cost-effective to replace the DERs with a wires build-out.

Approach

If it is cost-effective to use one or more generation DERs to defer a wires-DPA expansion plan, that approach will be taken. A typical benefit/cost test will be used to determine if the wires build-out should be pursued. At this time, we use only a simple shareholder benefit/cost test. The wrinkle in our approach is to determine how many years a build-out can be deferred and how many DER units will be needed for the deferral.

Assume that it is January 1st of Year 0, and the distribution planners of the local utility must decide whether to pursue a traditional build-out to meet load growth in a DPA or to install a DER.[*] Whichever alternative is chosen, it must be in place by December 31st of Year 0 to meet the expected load growth in Year 1.

Assume the DER is installed. On January 1st of Year 1, determine whether the build-out can be deferred another year if additional DERs are installed near/next to the DER that was installed in Year 0. If cost-effective, then install the extra DERs. Continue with that approach in subsequent years until it is no longer cost-effective to install more DERs. Then, the build-out is begun, and the existing DERs are uninstalled.

Intuitively, it may seem appropriate to always install DERs if the addition of their capital cost ($/kW-yr) plus installation and removal costs ($/kW), fixed operations and maintenance costs (O&M) and variable operating costs are less than the avoided costs of a traditional build-out. Some generation DER capital costs are fairly low (such as a natural gas fueled genset), but their variable operating costs tend to be higher than energy served from central stations. As more and more DERs are installed, the number of hours that each DER must run to clip the peak of a DPA load-duration curve must increase. This is because the DPA load-duration curve rises due to load growth each year. In tandem, over time, deferral costs fall. Together, both factors may put a brake on DER cost-effectiveness. If that were not so, then central station units should be decommissioned and replaced with DERs in every DPA.

[*] At this point, it does not matter what entity installs the DER — whether a utility or an outside vendor.

Assumptions

1. A DER installation in a DPA will not affect the central station generation (G) and transmission (Tr) avoided costs, because the DER capacity is assumed to be negligible compared to central station capacity. Also, G and Tr avoided costs do not change over time.
2. There is no uncertainty. Projected load growth materializes as projected. Also, upgrade costs and DER costs are known with certainty.
3. Distribution reliability is identical whether a wires build-out is completed or if a DER installation is used to defer the wires upgrade.
4. DER involves only generation devices. Yearly DER rentals are available in a competitive market, and DERs are available in divisible units. That is, if we need a 392kW DER, it is available. Also, the $/kW cost of DERs does not vary by size.
5. The combination of DER capital costs and operating costs cannot be so low that central stations are completely replaced by DERs.*
6. The value R is the appropriate cost of capital – expressed as a rate – for the utility and for the corporation that installs and operates the DER. That is, there are no tax laws or differences in corporate structure that would result in different costs between the utility and the DER business owner. The DER business owner may or may not be the utility.
7. DPA load-duration curves do not change shape during the years. Rather, they simply shift upward each year due to perfectly predictable load growth.
8. Inflation is assumed to be zero.

Load-duration Curve

A key element in our approach is the load-duration curve (LDC) in a DPA. If DERs are used to serve DPA peak load growth, it means that more DERs are needed each year to serve more and more local load unless a DPA build-out is pursued. Below is a mathematical description of a DPA LDC that allows for a prediction of the amount of load that must be served by DERs and the number of hours the DERs must operate to serve that load.

Also described mathematically is a load-duration curve for a typical DPA. At first pass, the most important consideration is to establish a workable mathematical definition. More precise functions could be developed by fitting a polynomial function that is a series of terms involving time raised to successively higher orders. So, it is advisable to start the process more simply.

The following criteria are defined:

LDC = Load-duration curve for a particular DPA

LF = Load factor for a particular DPA

* If DERs were very inexpensive, the current central system would disappear, because it would be rapidly replaced by local generation. This does not preclude DERs being less expensive in some high cost DPAs and therefore being cost effective for several years.

L = Load in Year 0 in the DPA at any particular hour

PL = Peak load in Year 0 in the DPA

BL = Baseload in Year 0 in the DPA – that is, the load at Hour 8760

T = Hour from 0 to 8760 hours

LG = Yearly load growth in percent in the DPA

Y = Year. Year 0 is the current or beginning year; future years are 1, 2, 3, *etc.*

A = Constant set by user: larger values for LDC with a higher LF; smaller values for LDC with lower LF.

exp = the value of e – the base of the natural logarithm – raised to the specified power.

Let (LF)L = $[(PL - BL) \times \exp(- T^2/A) + BL] \times [1+LG]^Y$(LF) be a mathematical description of an LDC for a DPA in Year Y.

For example, let PL = 5000 kW; BL = 1000 kW; A = 500,000. Let LG = 3% and Y = 0, the current year. Then the load (L) at T is

9. T = 200 (the highest 200th hour) = $[(5000 - 1000) \times \exp(- 200^2/500{,}000) + 1000] \times (1+3\%)^0 = 4{,}692$ kW.

In the cost/benefit test to follow, what is needed is the number of hours (T) that a DER must operate to "shave" the peak load so that an upgrade can be avoided. Solving for T, we obtain

$$T = \text{square root } [-A \times \ln((L-(1+LG)^Y \times BL)/((1+LG)^Y \times (PL - BL)))].$$

Now, let's assume that a DER must be able serve 300 kW for the example above. The next question is: *How many hours must the DER operate to do this?* After reducing peak load by 300 kW using a DER, L becomes 4,700 kW. Solve for T

$$T = \text{square root } [-500{,}000 \times \ln(((4700-(1+3\%)^0 \times 1000)/ ((1+3\%)^0 \times (5000-1000)))]$$

$$= 195 \text{ hours.}$$

The next step is to investigate what happens to the number of hours the DER must operate in subsequent years to clip the peak. Let Y = 1. Now, how many hours must the DER be run to cut 300 kW from the start year peak load? Solve for T where we let Y =1 and

$$T = \text{square root } [-500{,}000 \times \ln(((4700-(1+3\%)^1 \times 1000)/((1+3\%)^1 \times (5000-1000))]$$

$$= 238 \text{ hours.}$$

Of course, the number of hours that the DER must run in the subsequent year must increase, so that only 4700 kW of peak load will be served from the central system. In Year 2, T rises to 274 hours and so on for future years.

Benefit/Cost Test

1) Traditional Avoided Costs

G = \$/kW-yr central station avoided costs

Tr = \$/kW-yr transmission avoided costs

D = \$/kW-yr avoided costs computed using the deferral method

X = the distribution expansion plan costs (\$)

E = \$/kWh central station energy costs

LS = peak period line losses in percent (line losses in off-peak periods is assumed to be negligible compared to peak losses)

The deferral value (D) equals the build-out cost (X) times the factor R/(1+R). R is the cost of capital for both the utility and the corporation who installs and operates the DER for the benefit of the utility:

$$\text{Total Avoided Costs (TAC)} = G + Tr + D + E \times (1+LS) \times T.$$

Note that E is multiplied by T, because T is the number of hours that the DER will operate, releasing the central system to supply energy to other load centers.

2) DER Costs

DERC = DER Costs in \$/kW-yr, including fixed operations and maintenance (O&M), installation and removal costs. Yearly rental rates are available in a perfectly competitive market.

VC =Variable Costs per kWh = Heat Rate × Gas Costs + variable O&M in \$/kWh.

3) Benefit /Cost Test per kW

On January 1st of Year 0, distribution planners must decide to either build-out the DPA with traditional wires or install a DER. One of these alternatives will be done and completed by December 31st. Net benefits of installing a DER are*

$$\text{Year 0 per kW Net Benefit} = G + Tr + D_0 + E \times (1+LS) \times T - (DERC_0 + VC \times T_0).$$

D_0 and T_0 are subscripted 0 to refer to the year in which the build-out or DER decision has to be made. D_0 refers to distribution-avoided costs that are pushed from Year 0 to Year 1 if the DER choice is made. T_0 refers to the number of hours that the DER must operate in Year 1 to defer the upgrade at least through Year 1.

Below, net benefits are rewritten to contain two terms – one with the capital costs and the other the variable costs

$$\text{Year 0 per kW Net Benefit} = [G + Tr + D_0 - DERC_0] + [(E \times (1+LS) - VC) \times T_0].$$

* If the net benefit is greater than 0, the benefit/cost (B/C) ratio will be greater than 1. If it equals 0, the ratio is 1, and if it is negative, the ratio is less than 1. It is easier to write the above equation so that a division is not required, but the above approach is identical to a B/C ratio approach.

Net benefit depends on the relationship among the capital costs in the first term and variable costs in the second term. If the central system avoided costs plus the DPA deferral value is greater than the DER cost, the DER installation will probably yield a positive net benefit. Nevertheless, the net benefit also depends on the latter term that may or may not be positive. It will likely be positive if the local area peaks when the system peaks, at which time system energy costs will likely be higher than DER variable costs. On the other hand, if the local area peak does not coincide with the system, system energy costs may be relatively inexpensive compared to DER variable costs. If so, the latter term would be negative.

An immediate implication is that DER build-outs will be slightly less cost-effective in DPAs in which the local peak does not coincide with the system peak.

4) Benefit /Cost Test in Year 0

The above equation refers to a per-kW of load deferral. This approach is fine if we are concerned with a one-year deferral, but we are interested in the number of years that DPA build-outs can be cost-effectively deferred. We must multiply the net benefit above by the amount of load growth that must be deferred to avoid the build-out. This is the variable $[PL \times (1+LG)^1 - PL]$ defined above. Any load above PL will exceed maximum allowable load. By the way we constructed this problem, the load growth of $[PL \times (1+LG)^1 - PL]$ that equals $PL \times LG$ will obviously exceed PL. $PL \times LG$ is also the size of the DER that is needed. That is, $DERC_0$ equals $PL \times LG$.

The total net benefits are calculated thus

$$\text{Year 0 Total Net Benefit} = [[G + Tr + D_0 - DERC_0] + [(E \times (1+LS) - VC) \times T_0] \times PL \times LG.$$

5) Benefit /Cost Test in Year 1

Let's assume that in Year 0 it was determined that the DER installation was cost-effective. On January 1st of Year 1, the evaluation is undertaken again to determine whether to build-out or to add more DER capacity by December 31st of Year 1. The Year 1 net benefits are as follows

$$\text{Year 1 Total Net Benefit} = [[G + Tr + D_1 - DERC_0 - DERC_1] + [(E \times (1+LS) - VC) \times T1] \times [PL \times (1+LG)^2 - PL].$$

Load growth over two years is now $PL \times (1+LG)^2 - PL$. But this load growth is shared between Year 0 and Year 1. In Year 0, it is $PL \times (1+LG)1 - PL$, so load growth in Year 1, is

$$[PL \times (1+LG)^2 - PL] - [PL \times (1+LG)^1 - PL] = PL \times [(1+LG)^2 - (1+LG)^1].$$

We could more easily model yearly load growth by saying it is a constant amount of load in Year 0. Therefore, if more DER is adopted in Year 1, the amount ($DERC_1$) would equal

$$PL \times [(1+LG)^2 - (1+LG)^1].$$

As above,

$$DERC_0 \text{ equals } [PL \times (1+LG)^1 - PL].$$

The distribution avoided costs in Year 1 ($D_{1)}$ will change. In most circumstances, it will begin to provide a brake that will limit the ultimate amount of DER applications from completely replacing central station generation.

First, note the relationship between D_1 and D_0. As shown above, D_0 equals X the upgrade costs deferred in Year 0 divided by the load growth that must be deferred. This equals

$$[X - X/(1+R)]/\ [PL \times (1+LG)^1 - PL].$$

The first term reduces to $X \times R/(1+R)$ which is the very familiar one-year deferral value. The second term reduces to $PL \times LG$ which is simply the load growth during Year 1. Therefore, the Year 0 deferral value per kW equals

$$[X \times R/(1+R)]/[PL \times LG].$$

A two-year deferral value equals

$$[X - X/(1+R)^2]/[PL \times (1+LG)^2 - PL].$$

It is important to consider this formula carefully. Both the numerator and denominator grow over time; however, the numerator grows at a *decreasing* rate over time while the denominator grows at an *increasing* rate over time. Therefore, the ratio falls over time. This reduces the cost-effectiveness of DERs in subsequent years.

The relationship between system energy costs (E) and DER variable costs (VC) will provide another check on unlimited DER deployment. Look at the last term in Year 1 net benefits

$$[(E \times (1+LS) - VC) \times T_1].$$

If DER is cost-effective in the second year, the number of hours (T_1) that both DERs (that is, the DER installed in Year 0 and the DER installed in Year 1 must run increases relative to Year 0). As this continues into subsequent years, the load coincidence between the central system and the DPA will fall. This will result in the system energy costs falling over time. If this term was previously positive, it will become more negative over time, resulting in lower net benefits.

6) Benefit /Cost Test in Year 2

Again, if a DER was installed at the end of both Years 0 and 1, we must decide if we will install more DERs in Year 2 to meet load growth in Year 3. The approach is identical to the above

$$\text{Year 2 Total Net Benefit} = [[G + Tr + D_2 - DERC_0 - DERC_1 - DERC_2]$$

$$+ [(E \times (1+LS) - VC) \times T_2]] \times [PL \times (1+LG)^3 - PL].$$

As above, D_2 falls relative to D_1. Also, T_2 rises. As argued above, both reduce the possibility of more DER capacity.

Summary

The amount of viable DER capacity depends on the characteristics of the DPA that is being analyzed. A next step would be to build a simple spreadsheet model that incorporates these equations to evaluate some real cases.

Appendix C – Outage Costs and Service Reliability

SAIDI and SAIFI

Utilities often use well-established reliability criteria for evaluating electric service reliability (service reliability). Most common are the System Average Interruption Duration Index (SAIDI) and the System Average Interruption Frequency Index (SAIFI). Those indices describe the duration and frequency, respectively, of sustained interruptions experienced by customers of a utility in one year. The Institute of Electrical and Electronics Engineers (IEEE) defines a "sustained interruption" as any interruption lasting five minutes or more.[C1]

Nevertheless, according to Joe Eto, *et. al.:*

> *Although SAIDI and SAIFI are useful for assessing the costs and effects of power interruptions, these data are often either not collected by utilities or are collected inconsistently (Warren et. al. 2003[C2]). That is, the information collected by utilities, if it is collected (and reported) at all, varies in the details or variables that are recorded. Thus, a major source of uncertainty is that many reliability events that have measurable cost consequences for the customers who experience them are simply not counted.*[C1]

But, more importantly, SAIDI and SAIFI are not denominated in dollars. Instead, they are targets or required levels, or indicators. Without more robust criteria to ascribe monetary value to the cost incurred by customers for outages, it will be challenging to quantify risk associated with (T&D) investments. Also, without a more sophisticated approach to optimizing T&D investments involving risk-adjusted cost, some important benefits from modular distributed energy resources (DERs) to optimize utility T&D investments will be obscured.

Value of Unserved Energy

For this study, the risk calculation included a criterion called "cost of unserved energy" to represent the cost that would be incurred by a utility customer if the T&D alternative results in a service outage. Without such a monetized value (*i.e.*, if using reliability indices), the evaluation would have been much different.

The result would be driven by the need to meet the minimum level of service reliability rather than risk-adjusted cost optimization because, essentially, the indices are treated as if they indicate the optimal solution. The implicit premise is that it is too costly for service reliability to be lower than a certain golden value. That approach usually favors the very reliable utility upgrade. Certainly any approach that would result in service reliability below the accepted threshold would not be considered.

It may be quite challenging to establish a credible value for cost of unserved energy – for any given circumstance – given the broad diversity of customers and dearth of data needed to establish such a value. Nonetheless, it seems quite important that society and the utility industry improve their understanding of the cost tradeoffs between various possible solutions with varying degrees of reliability.

The assumed value for unserved energy is described in Appendix D and shown in Table D-1.

References

[C1] Hamachi LaCommare, Kristina. Eto, Joseph H. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. Lawrence Berkeley National Laboratory, Energy Analysis Department. September 2004.

[C2] Warren, C. Pearson, D. Sheehan, M. *A Nationwide Survey of Recorded Information Used for Calculating Distribution Reliability Indices*. IEEE Transaction on Power Delivery, 18 (2). 2003.

Appendix D – Elements of T&D-related Risk

Introduction

Ultimately, transmission and distribution (T&D) risk is based on the possibility that costs will be incurred. This section provides an overview of the values assumed for the cost elements of risk.

The risk addressed in this study is related to T&D equipment overloading that could occur if a specific alternative is used. Potential overloading costs include 1) T&D equipment damage (damage) expressed in terms of lost life, 2) utility lost revenue during outages (lost revenue), 3) utility labor for responding to interruptions (response cost), and 4) customer cost for 'unserved energy' during outages.

Unless a distributed energy resource (DER) is sized based on the worst case, the risk associated with DER undersizing must also be included in the evaluation of DERs to provide marginal capacity *in lieu* of new or additional T&D equipment. (Readers should note that risk caused by uncertainty related to the electric supply was not addressed for this study.)

Elements of T&D Risk

An important theme for this report is that the elements of risk which are estimated must be expressible in terms of a denominated *financial* cost. Following is a list of the elements of T&D-related risk that may affect specific T&D capacity investments. Note that almost all risk included in the list below is related to one phenomenon — overloading of T&D equipment:

- Utility Equipment Damage due to T&D Overloading
    - Equipment life reduction
    - Cost for premature maintenance that is not included in the estimate of equipment damage (cost) based on equipment loss-of-life
    - Major repairs – permanent or temporary – required to place damaged equipment back into service
- Utility Cost for Outage(s) due to Overloading
    - Response cost – primarily labor to troubleshoot and reset/re-energize
    - Lost revenue
    - General liability (*e.g.*, lawsuits, attorney fees)
    - Fines and other regulatory action
    - Damage to goodwill and reputation
- End-user Cost for Outage(s) due to Overloading
    - Lost productivity and/or extra labor costs
    - Lost sales and/or reduced revenues
    - Product damage

- Equipment damage
- Injury or physical harm
- General liability
- Hassle and annoyance

The following costs – that are the elements of T&D-related risk – were estimated for this study:

- Utility equipment damage due to T&D overloading
- Utility response cost for outage(s) due to T&D overloading
- Utility lost revenue due to T&D overloading (and resulting service outages)
- End-user cost for outage(s) due to T&D overloading

Utility Costs

T&D Equipment Damage

Utility T&D equipment damage due to overloading was calculated assuming 13 years of useful life for the existing 12,000 kW equipment. The equipment's replacement cost is $30/kW, for a total of

12,000 kW × $30/kW = $360,000.

The *annualized* cost to own that equipment is

$360,000 × 0.11 fixed charge rate = $39,600 per year.

So, for the equipment's 13 years of remaining life there are remaining *carrying charges* of

$39,600 per year × 13 years = $514,800.

More details about the existing T&D equipment's life and cost-related considerations are provided in Appendix K.

Utility Outage Response Cost

A flat $1,000 is assumed for the cost incurred by the utility to respond to a service outage. The response cost is mostly for labor and for modest repairs needed, if any. Actions required may include, for example, resetting circuit breakers and visual inspection(s) of affected equipment, reading charts or other sources of relevant data and reporting.

Utility Lost Revenue

Utility lost revenue is calculated based on 1) the prevailing energy price, 2) the amount of time that service is out, and 3) the magnitude of the unserved load. For the purposes of this study, the prevailing electricity price assumed is 15¢/kW. Outage frequency, magnitudes and durations are described in Appendix L. In all cases, when an outage occurs the unserved load is the demand existing when the outage occurs.

Utility Risk Associated with Upgrade Project Delays

For the do T&D upgrade approach, there is a 15% chance of construction delay assumed. The related risk is calculated as 15% of the risk for the do nothing approach.

Electricity End-user Costs for Unserved Energy

A value of $3.60/kWh of unserved energy demand was assumed for this evaluation.[D1] This value serves as a proxy for costs incurred by customers and for any fines, litigation cost and liability incurred by the utility due to outages.

Though a financial value for this criterion may not be included in T&D planning exercises, to one extent or another, this criterion *is* addressed. The $3.60/kWh value is used as a way to make that important consideration explicit.

This value is treated as a composite representing the actual cost for various customer classes. Residential customers are assumed to have a low-cost of unserved energy. Commercial customers have higher costs due to losses such as lost sales and productivity and product spoilage. Manufacturing entities tend to have the highest costs — at stake are product or equipment damage, lost productivity, lost sales, *etc*.

The assumed customer mix, their respective cost of unserved energy and the composite value of unserved energy are shown in Table D-1.

Table D-1. Composite Value of Unserved Energy

Customer Class	% of Customers	Value of Unserved Energy ($/kWh)
Residential	65%	0.15
Commercial	25%	4.0
Manufacturing	10%	25.0
Composite	100%	3.60

References

[D1] Hamachi LaCommare, Kristina. Eto, Joseph H. *Understanding the Cost of Power Interruptions to U.S. Electricity Consumers*. Lawrence Berkeley National Laboratory, Energy Analysis Department. September 2004.

Appendix E – Financial and Accounting Philosophy for T&D Equipment Cost and Damage

Each organization and stakeholder group uses its own financial criteria, evaluation metrics, accounting procedures and philosophy. For the purposes of this study, a simplistic approach is used to account for financial results. The simplifying financial assumptions and approaches used are meant to be auditable and to yield realistic results. (See Appendix D for details about related assumptions used for this report).

Estimating Annual Revenue Requirement

The total installed cost for utility capacity is assumed to include the price of the equipment plus engineering and construction costs. To estimate the annual *revenue requirement* – the amount that ratepayers must pay to cover one year of ownership of the equipment – that installed cost is multiplied by a *fixed charge rate*. The resulting value (installed cost × fixed charge rate) reflects all costs associated with owning the equipment for one year. Cost elements include dividend and interest payments, depreciation or return of capital, taxes, and insurance. The fixed charge rate does not reflect expenses incurred to operate the equipment such as labor and routine maintenance.

The fixed charge rate assumed for this study was 0.11. The annual revenue required for a transmission and distribution (T&D) project whose installed cost is $1,000,000 is calculated as

$$\$1,000,000 \times 0.11 = \$110,000 \text{ per year.}$$

One unique facet of this approach is that utility prices are based on the "revenue requirement." Revenue requirement is the level of revenue required to pay all utility costs, including expenses, interest, taxes, and dividends. So, utility price is entirely cost-based rather than being a function of cost and normal market forces. The revenue requirement topic is addressed in more detail in Appendix M.

Accounting for T&D Equipment Damage

Useful Life

Knowing or estimating equipment remaining useful life is usually challenging. A key reason is that good historical records about equipment operating conditions are rarely available; that may change in the future. Nonetheless, there is a growing body of information available about the subject. Also, there are tools that can be used to estimate equipment's remaining useful life and to estimate effects on equipment for various "events" where an event is characterized by the magnitude and duration of a given overloading incident.[E1]

For many T&D upgrades, a significant portion of the existing equipment is removed and then placed into a rotating stock of equipment. This is especially important for transformers which are a high-cost element of the distribution infrastructure.

Equipment Damage

It is the equipment placed into rotating stock for which damage is important because damage that reduces the equipment's useful life is an actual cost borne by utility ratepayers. For a given upgrade project, if equipment that is removed will be retired, then equipment damage is irrelevant. (See Appendix K for more details about treatment of damage-related costs.)

Timing of Charges for Equipment Damage

Depending on the perspective taken, it may be appropriate to account for damage a) as it is incurred, b) using equal amounts over the time period during which the damage occurs or c) when replacement is made. For the evaluation in this report, damage cost is treated as if it is incurred as it occurs (using the economic approach). In that case, the amount that has been allocated for damage is treated like a sinking fund.[*]

Reference

[E1] Erickson, Jon. *Underground Cable Failure Tracking, Underground Cable Failure Rates – San Diego Gas & Electric*. ICC Educational Program. November 3, 2004.

Available at: http://www.ewh.ieee.org/soc/pes/icc/subcommittees/subcom_e/education/2004/F2004_Erickson.pdf.

[*] A sinking fund contains monies that have been set aside in a special account to pay for an anticipated future purchase of capital assets.

Appendix F – T&D Upgrade Avoided Cost

Based on a survey of several relevant sources, a base-case value of $250/kW of upgrade capacity is assumed. It intended to reflect a cost that is typical, though perhaps somewhat higher than the mean value.

Based on analysis by the Energy Foundation from 1997, and as shown in Figure F-1, distribution costs range significantly among utilities and among locations within utilities. For the four utilities shown, the system average marginal distribution capacity cost ranges from $73/kW to $556/kW, and individual planning area marginal costs range from a low of $0 to a high of $1,795 per kW.[F1][F2]

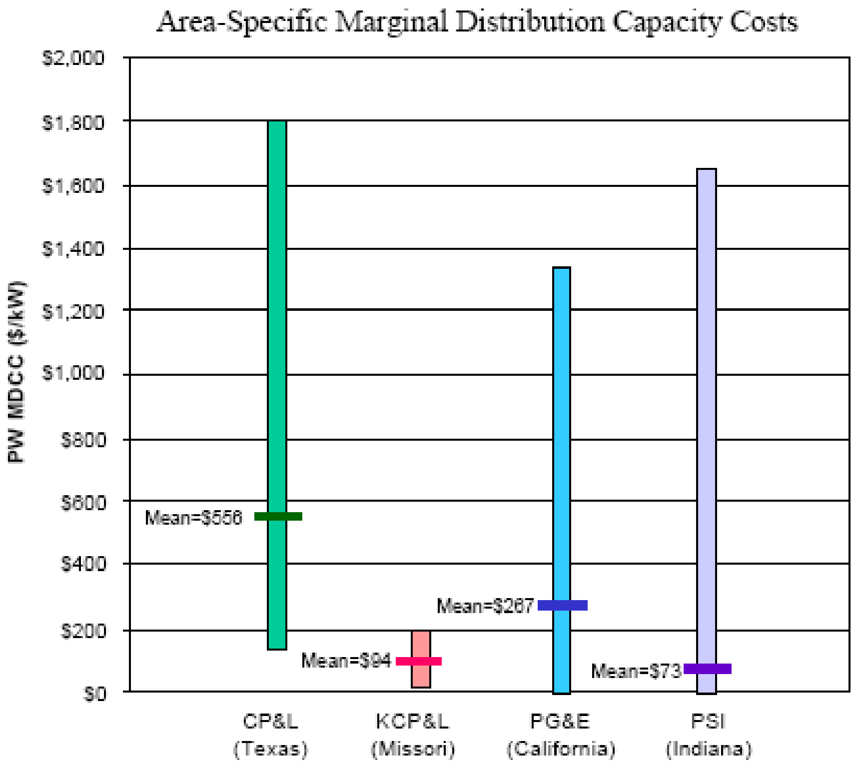


Figure F-1. Variability of distribution marginal cost.
Source: Energy Foundation. Adapted from Woo, Heffner, Horii, Lloyd (1997), "Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution," IEEE Transaction on Power Systems (PE-493-PWRS-0-12-1997).

Although the values above are from 1997 they are still useful if assuming that the variation of T&D capacity cost has not changed dramatically since 1997. As an aside, to escalate the values above to 2013 values they should be multiplied by a factor of about 1.025^16 = 1.48 to account for general price escalation of 2.5% per year.

The transmission and distribution (T&D) upgrade cost assumed is $250/kW added. That value is based on what might be called a composite cost for utilities to add distribution capacity. It is calculated by dividing the entire capital budget for distribution additions by the increased peak demand for the year. T&D capital spending was ascertained using Federal Energy Regulatory Commission Form 1 data for several large investor owned utilities.[F3]

The upgrade example evaluated for this report will increase T&D capacity from 12,000 kW to 16,000 kW (adding 4,000 kW). The upgrade total cost is

4,000 kW *added* × $250/kW = $1,000,000.

The annual revenue requirement is

$1,000,000 × 0.11 (fixed charge rate) = $110,000/year.

Based on the nameplate rating of the upgraded equipment (16,000 kW) so the cost per kW *installed* is

$1,000,000 ÷ 16,000 kW = $62.5/kW.

For the purposes of this study – to demonstrate the concept by generating realistic results – the specific utility T&D equipment being upgraded is not nearly as important as the cost required to add capacity. Presumably, most cases involve transformer upgrades, new substation exit circuits, or expensive distribution circuits, especially underground cables.

Of course, as with any other population, the cost per kW of capacity added for any given circumstance may be significantly more than or less than $250/kW added. In fact, one study indicated that "annual electric distribution avoided costs by planning area can vary by a factor of seven within a utility."[F4]

Many situations require low-cost improvements. Presumably, most of those cases are not compelling candidates for the type of evaluation described in this report. Also, some upgrades cost considerably more than $250/kW added. In many cases, those are good candidates for a risk-adjusted-cost assessment.

References

[F1] Knapp, Karl E. Gordon, Frederick M. Martin, Jennifer. Price, Snuller. *Costing Methodology for Electric Distribution System Planning*. Prepared for The Energy Foundation. November 2000.

[F2] Woo, Heffner. Horii, Lloyd. *Variations in Area- and Time-Specific Marginal Capacity Costs of Electricity Distribution*. IEEE Transaction on Power Systems. PE-493-PWRS-0-12-1997.). 1997.

[F3] Hadley, S. W. Van Dyke, J. W. Poore, W. P. III. Stovall, T. K. *Quantitative Assessment of Distributed Energy Resource Benefits*. ORNL/TM-2003/20. May 2003. p. 35.

[F4] *Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs*. Prepared for California Public Utilities Commission. Submitted by Energy and Environmental Economics, Inc. and Rocky Mountain Institute. October 2004. p. 92.

Appendix G – Diesel Engine Generator Rental

Table G-1 shows data and interim calculations used to estimate rental charges for diesel engine generators (gensets) for T&D deferral. Fuel cost reflects diesel fuel price of $4.25 per gallon.

Table G-1. Diesel Engine Generator Rental and Fuel Cost

Rental Charges ($)

			Month	
Duration =>	$/Day	$/Week	$/Month	$/kW-month
250 kW	600	1,539	4,455	17.82
350 kW	980	2,212	6,083	17.38
500 kW	1,500	3,200	8,580	17.16
1,000 kW	2,070	5,170	15,510	15.51

Fuel Use and Cost

Fuel Use (gallons per hour)

Loading =>	25%	50%	75%	100%
250 kW	5.0	8.0	12.0	15.0
350 kW	7.0	11.2	16.8	21.0
500 kW	10.0	16.0	24.0	30.0
1,000 kW	19.0	31.0	46.0	58.0

Fuel Efficiency (%, HHV)

Loading =>	25%	50%	75%	100%
250 kW	30.8%	38.4%	38.4%	41.0%
350 kW	30.8%	38.4%	38.4%	41.0%
500 kW	30.8%	38.4%	38.4%	41.0%
1,000 kW	32.4%	39.7%	40.1%	42.4%

Fuel Cost (¢/kWh)

Loading =>	25%	50%	75%	100%
250 kW	34.0	27.2	27.2	25.5
350 kW	34.0	27.2	27.2	25.5
500 kW	34.0	27.2	27.2	25.5
1,000 kW	32.3	26.4	26.1	24.7

Fuel Cost ($/hour)

Loading =>	25%	50%	75%	100%
250 kW	21.3	34.0	51.0	63.8
350 kW	29.8	47.6	71.4	89.3
500 kW	42.5	68.0	102.0	127.5
1,000 kW	80.8	131.8	195.5	246.5

Figure G-1 shows, graphically, the rental charges that apply for various generator sizes and for various rental periods. For the first seven days the daily value is used. For days seven to 30 the weekly rental charge is used and for days 30 to 360 the monthly rental charges are used.

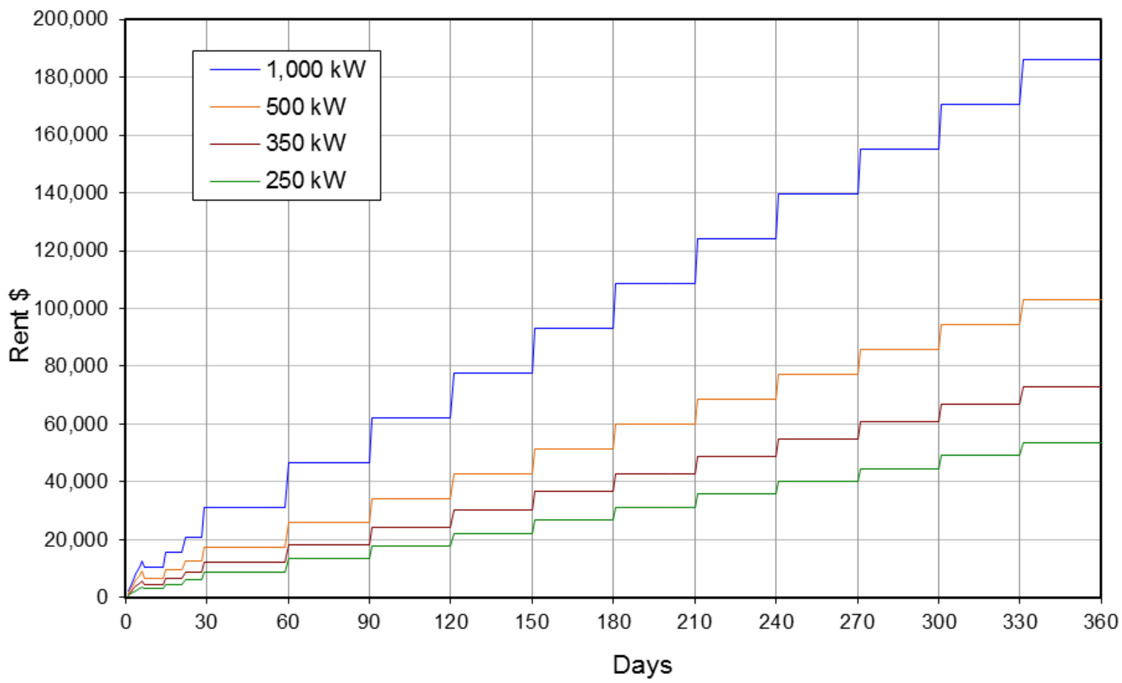


Figure G-1. Diesel engine generator rental charges summary.

Tables G-2 and G-3 below show cost calculations for the two alternatives, including genset rental plus fuel cost. A capacity factor of 75% of rated power is assumed. Genset reliability is assumed to be 97.5% for both alternatives. Both alternatives generate the same amount of energy.

The two alternatives are:

Alternative 1 a) rent one 250 kW genset for three months and operate it at for 50 hours at an average of 75% of its rated power and b) rent one 250 kW genset for five months and operate it for 100 hours at an average of 75% its rated power, for a total of 500 kW.

Alternative 2 a) rent one 250 kW genset for three months and operate it for 80 hours at an average of 75% of its rated power and b) rent one 350 kW genset and operate it for 50 hours at an average of 75% of its rated power, for a total of 600 kW.

Table G-2. Diesel Engine Generator Rental and Fuel Cost: Two 250 kW Units

			Rent Cost		Fuel Cost				Total Cost	
Power	Units	Months	$/year	$/kW-year	Operation Hours/ Per Year	Average Loading	$/year	$/kW-year	$/year	$/kW-year
250 kW	1	3	13,365	53.5	50	75%	2,550	10.2	15,915	63.7
250 kW	1	5	22,275	89.1	100	75%	5,100	20.4	27,375	109.5
500 kW			35,640	71.3	28,125	kWh/year	7,650	15.3	43,290	86.6

Table G-3. Diesel Engine Generator Rental and Fuel Cost: One 250 kW Unit and One 350 kW Unit

			Rent Cost		Fuel Cost				Total Cost	
Power	Units	Months	$/year	$/kW-year	Oper-ation Hours/ Per Year	Average Loading	$/year	$/kW-year	$/year	$/kW-year
250 kW	1	3	13,365	53.5	80	75%	4,080	16.3	17,445	69.8
350 kW	1	5	30,415	86.9	50	75%	3,570	10.2	33,985	97.1
600 kW			43,780	73.0	28,125	kWh/year	7,650	12.8	51,430	85.7

Note that, as described elsewhere in this report there is an 84% chance that overloading will not exceed the T&D equipment's rated load carrying capacity by more than the assumed overload floor (4%). Below that value: 1) no damage (to the existing T&D equipment) occurs and 2) no outages occur. As a result, there is a good chance that the gensets will not have to be operated at all. In that case, the direct cost for genset rental is for the rental charge only (*i.e.*, no fuel related cost is incurred).

Tables G-4 and G-5 below show cost for the two alternatives involving genset rental only (*i.e.*, cost if the gensets do not have to be operated).

Table G-4. Diesel Engine Generator Rental Cost: Two 250 kW Units

			Rent Cost		Fuel Cost				Total Cost	
Power	Units	Months	$/year	$/kW-year	Oper-ation Hours/ Per Year	Average Loading	$/year	$/kW-year	$/year	$/kW-year
250 kW	1	3	13,365	53.5	0	75%	0		13,365	53.5
250 kW	1	5	22,275	89.1	0	75%	0		22,275	89.1
500 kW			35,640	71.3	0	kWh/year	0		35,640	71.3

Table G-5. Diesel Engine Generator Rental: One 250 kW Unit and One 350 kW Unit

			Rent Cost		Fuel Cost				Total Cost	
Power	Units	Months	$/year	$/kW-year	Oper-ation Hours/ Per Year	Average Loading	$/year	$/kW-year	$/year	$/kW-year
250 kW	1	3	13,365	53.5	0	75%	0		13,365	53.5
350 kW	1	5	30,415	86.9	0	75%	0		30,415	86.9
600 kW			43,780	73.0	0	kWh/year	0		43,780	73.0

Reference

[G1] *Rental Charges for Towable Diesel Generators in San Francisco Bay Area*. Provided by Sunbelt Rentals via website. http://www.sunbeltrentals.com/equipment/category.aspx?id=s391. November 8, 2012.

Appendix H – Load Growth and Ambient Temperature Uncertainty and Resulting Excess Demand

Excess demand is defined as electricity end-user demand (power draw) that exceeds the load carrying capacity of the T&D equipment serving the respective end-users. Maximum effective demand is the maximum scenario-specific value for excess demand. (Scenario-specific *maximum* excess demand values are shown below in Table H-1.)

Importantly, although there is only one *maximum* excess demand for a given scenario, there may be more than one excess demand value for a given scenario. That occurs if the scenario is one of the more extreme ones where extreme means that there is some combination of a) significant inherent demand growth, b) significant block load additions and c) significantly high ambient temperature. (See Appendix L for details about overloading frequencies assumed.)

The values in Table H-1 are the assumed values and corresponding probabilities for three criteria: 1) inherent load growth, 2) block load additions and 3) weather (*i.e.,* maximum ambient temperature).

Table H-1. Load Growth and Weather Uncertainty Assumptions

Load Related Uncertainties and Probabilties

Inherent Peak Demand Growth

	Low	=>	High		
Probability	20.0%	60.0%	20.0%	check sum	100.0%
Load Growth (kW)	100.0	200.0	300.0	Expected Value	200 kW
Growth	+0.9%	+1.7%	+2.6%		

Block Load Addition(s)

	Low	=>	High		
Probability	15.0%	50.0%	35.0%	check sum	100.0%
Block Load (kW total added)	0.0	250.0	500.0	Expected Value	300 kW

Weather Conditions -- Max Temp.

	Low	=>	High		
Probability	90.0%	7.5%	2.5%	check sum	100.0%
Ambient Temperature	105.0ºF	107.5ºF	110.0ºF	Expected Value	105.31ºF

Weather Related Incremental Load (for A/C)

	Low	=>	High		
Probability	90.0%	7.5%	2.5%		
Ambient Temperature	105.0ºF	107.5ºF	110.0ºF		
peak load, +/- % of peak load @ design temperature.	0.0%	5.0%	10.0%	Expected Value	+0.6%

The probability tree in Table H-2 shows scenario-specific and expected values for 1) inherent demand growth and resulting peak demand, 2) block load additions and the resulting peak demand, 3) maximum ambient temperature, 4) high-temperature-specific demand (*e.g.,* for air conditioning), 5) maximum peak demand and 6) maximum excess demand.

Note that scenarios in Table H-2 are characterized based on uncertainty assumptions that are shown in Table H-1. Values shown in Table H-2, for each scenario (end-state), reflect the sum of 1) peak demand growth, 2) block load additions (if any) and 3) high-temperature-related incremental demand (*i.e.,* for air conditioning and refrigeration).

Table H-2. Demand Growth, Temperature and Resulting Excess Demand

	Inherent Peak Demand Growth A			Block Load(s) A			Weather Considerations B				Demand		Maximum Excess Demand C				
Scenario	Prob-ability	Peak Demand Growth (kW)	Peak Demand w/Growth (kW)	Prob-ability	Block Load Added (kW)	Peak Demand w/Growth & w/Block Load (kW)	Prob-ability	Max. Ambient Temp. (°F)	Temp-erature-related Peak Demand Adder (%)	Incre-mental Peak Demand For Temp. (kW)	Maximum Peak Demand (kW)	Scen-ario Prob-ability	Max. Excess Demand (kW)	Max Excess Demand (%)	Max. Excess Demand > 4.0% Above Rating	Max Excess Demand > 7.0% Above Rating	Max. Excess Demand > 10.0% Above Rating
1	20.0%	100	11,800	15.0%	0	11,800	90.0%	105.0	0.0%	0	11,800	2.70%	0	0.00%			
2	20.0%	100	11,800	15.0%	0	11,800	7.5%	107.5	5.0%	590	12,390	0.23%	390	3.25%			
3	20.0%	100	11,800	15.0%	0	11,800	2.5%	110.0	10.0%	1,180	12,980	0.08%	980	8.17%	✓	✓	
4	20.0%	100	11,800	50.0%	250	12,050	90.0%	105.0	0.0%	0	12,050	9.00%	50	0.42%			
5	20.0%	100	11,800	50.0%	250	12,050	7.5%	107.5	5.0%	603	12,653	0.75%	653	5.44%	✓		
6	20.0%	100	11,800	50.0%	250	12,050	2.5%	110.0	10.0%	1,205	13,255	0.25%	1,255	10.46%	✓	✓	✓
7	20.0%	100	11,800	35.0%	500	12,300	90.0%	105.0	0.0%	0	12,300	6.30%	300	2.50%			
8	20.0%	100	11,800	35.0%	500	12,300	7.5%	107.5	5.0%	615	12,915	0.53%	915	7.63%	✓	✓	
9	20.0%	100	11,800	35.0%	500	12,300	2.5%	110.0	10.0%	1,230	13,530	0.18%	1,530	12.75%	✓	✓	✓
10	60.0%	200	11,900	15.0%	0	11,900	90.0%	105.0	0.0%	0	11,900	8.10%	0	0.00%			
11	60.0%	200	11,900	15.0%	0	11,900	7.5%	107.5	5.0%	595	12,495	0.68%	495	4.13%	✓		
12	60.0%	200	11,900	15.0%	0	11,900	2.5%	110.0	10.0%	1,190	13,090	0.23%	1,090	9.08%	✓	✓	
13	60.0%	200	11,900	50.0%	250	12,150	90.0%	105.0	0.0%	0	12,150	27.00%	150	1.25%			
14	60.0%	200	11,900	50.0%	250	12,150	7.5%	107.5	5.0%	608	12,758	2.25%	758	6.31%	✓		
15	60.0%	200	11,900	50.0%	250	12,150	2.5%	110.0	10.0%	1,215	13,365	0.75%	1,365	11.38%	✓	✓	✓
16	60.0%	200	11,900	35.0%	500	12,400	90.0%	105.0	0.0%	0	12,400	18.90%	400	3.33%			
17	60.0%	200	11,900	35.0%	500	12,400	7.5%	107.5	5.0%	620	13,020	1.58%	1,020	8.50%	✓	✓	
18	60.0%	200	11,900	35.0%	500	12,400	2.5%	110.0	10.0%	1,240	13,640	0.53%	1,640	13.67%	✓	✓	✓
19	20.0%	300	12,000	15.0%	0	12,000	90.0%	105.0	0.0%	0	12,000	2.70%	0	0.00%			
20	20.0%	300	12,000	15.0%	0	12,000	7.5%	107.5	5.0%	600	12,600	0.23%	600	5.00%	✓		
21	20.0%	300	12,000	15.0%	0	12,000	2.5%	110.0	10.0%	1,200	13,200	0.08%	1,200	10.00%	✓	✓	
22	20.0%	300	12,000	50.0%	250	12,250	90.0%	105.0	0.0%	0	12,250	9.00%	250	2.08%			
23	20.0%	300	12,000	50.0%	250	12,250	7.5%	107.5	5.0%	613	12,863	0.75%	863	7.19%	✓	✓	
24	20.0%	300	12,000	50.0%	250	12,250	2.5%	110.0	10.0%	1,225	13,475	0.25%	1,475	12.29%	✓	✓	✓
25	20.0%	300	12,000	35.0%	500	12,500	90.0%	105.0	0.0%	0	12,500	6.30%	500	4.17%	✓		
26	20.0%	300	12,000	35.0%	500	12,500	7.5%	107.5	5.0%	625	13,125	0.53%	1,125	9.38%	✓	✓	
27	20.0%	300	12,000	35.0%	500	12,500	2.5%	110.0	10.0%	1,250	13,750	0.18%	1,750	14.58%	✓	✓	✓

Checksum ok

Note A: For each scenario, add Inherent (Peak) Demand Growth to the Block Load Added (if any) to the previous year's peak demand.

Note B: For each scenario, add Temerature-related Peak Demand Adder (kW) (i.e. for incremental A/C and refrigeration use, if any).

Note C: For each scenario, sum Peak Demand Growth (kW) and Block Load added (kW) to temperature-specific value for Incremental Peak Demand for Temp. (kW). Values are scenario-specific *maximum* values.

	All End-States Raw*	Excess Demand > 0%	Excess Demand > 4.0%	Excess Demand > 7.0%	Excess Demand > 10.0%
Probability	100%	86.5%	16.1%	5.88%	2.13%
Demand exceeding *Projected* Peak (kW)	126	185	639	1,020	1,328
Peak Demand (kW)	12,276	12,335	12,789	13,170	13,478
Maximum Excess Demand (kW)	**276**	**335**	**789**	**1,170**	**1,478**
%	**2.3%**	**2.8%**	**6.6%**	**9.8%**	**12.3%**
Deferral Value ($/kW** of Perfect DER)	334	276	117	79.0	62.5

*Includes "load contraction" in scenarios when load declines.

**DER kW = Maimum Excess Demand.

Note: kW and $ values reflect proablility-weighted average (expected value) of "qualifying" scenarios.

Readers should note that there is a 16.1% chance that excess demand will not exceed the overloading floor (4%). That means that there is 83.9% chance there is no damage or outage-related cost.

Appendix I – Key Uncertainties Affecting T&D Expansion Planning

Introduction

Uncertainty is an important element of transmission and distribution (T&D) planning. To evaluate uncertainty and estimate risk, the first step is to characterize the primary sources of uncertainty. This appendix describes notable uncertainties that affect T&D expansion decisions.

Key T&D Planning Uncertainties

Load Growth

Inherent Load Growth

Inherent peak load growth (*inherent load growth*) reflects the annual rate at which existing peak load is growing – after accounting for both block load additions and weather conditions. The key driver of inherent load growth is economic growth. Demographic changes also affect inherent load growth.

Block Load Changes

In many regions or locations, block load changes can have a significant effect on the T&D system. Block load *additions* often involve new real estate development. They can also be a result of equipment additions at existing commercial or industrial facilities. Conversely, business closures or demolition of existing facilities may lead to a block load *reduction*.

In many cases, pending block load changes have been identified by the utility, though the timing of the change is often uncertain. In some cases, expected block load changes do not occur. Some block load changes are made with short notice to the utility.

Weather

Weather variability is an important uncertainty for T&D planners. It is common for T&D designs and decisions to reflect somewhat extreme weather conditions such as "one-year-in-ten."

For any given location or circumstance, ambient temperature is normally the most important criterion underlying the weather uncertainty, though relative humidity and/or wind speed may also be important.

Project Delays

Once a prioritized list of T&D projects is established, a next step is to estimate the resources needed to accomplish the upgrades, including, but not limited to, engineering/design staff, construction staff and capital needed to purchase new equipment. If equipment is not in the utility stock, it must be ordered. Also, arrangements must begin for environmental impact reports (EIRs), permits, and other compliance-related activities. In some cases, the utility may have to organize and hold community meetings and possibly re-engineer a project to address community concerns.

These and other factors are the bases for the T&D project delay uncertainty. Because many projects are planned one year in advance, a delay of several months may mean that a needed upgrade is not made before the peak demand season. If so, equipment overloading and outages may result.

In summary, some reasons that projects may be delayed include the following:

- Engineering, construction, or other staff shortages
- Budget constraints
- *Ex post facto* "priority-shift" – After an initial distribution construction plan (plan) is established, there is a change – additional information becomes available and/or conditions change – such that one or more projects are given a higher priority, after the fact, such that other projects are given a lower priority.
- Institutional delays (*e.g.,* permitting, EIRs, zoning, community concerns)
- *Ex post facto* re-engineering requirements
- Equipment delivery delays or delivery of incorrect equipment

Equipment Loading History

Unless good records are kept about demand served and/or equipment loading or equipment temperature over time, uncertainty about the remaining life of existing T&D equipment may not be trivial. Additionally, without that historical information, there may be uncertainty about the load-carrying capacity of the equipment (*i.e.,* the equipment's load-carrying capacity and/or tolerance of overloads may have been degraded) if it has been operated at high loading levels, for extended periods, more than a few times.

An implication of this uncertainty is that go/no-go decisions about a specific upgrade may be based on incorrect assumptions about whether the equipment can serve peak demand:

- If assuming too little damage, then the do nothing alternative has more risk.
- If assuming too much damage, then the upgrade may be made before it is needed, leading to lower asset utilization.

The conventional way to record equipment loading history has been via an analog plot on a circular piece of paper (a "circle chart"). The data on circle charts can be difficult or tedious to analyze, and often has data gaps.

To one extent or another, most utilities have long-term plans to improve monitoring and archiving of equipment loading history digitally, especially for transformers and substations. As that capability increases, uncertainty regarding equipment remaining life and reliability will decrease. For this study, the remaining life of T&D equipment life was treated as if it was known with certainty.

Peak Load Profile Change

After accounting for inherent load growth and block load changes, there may also be uncertainty about the peak load profile to which T&D equipment may be subjected. That uncertainty is especially important for modular electricity storage (MES) because such storage must have enough stored energy to serve peak demand.

Key factors that cause a change of the peak load profile include instances when 1) the mix of load types changes (*e.g.,* less industrial and more residential) and 2) the electricity use pattern changes for specific end-users (*e.g.,* a restaurant adds lunch to its schedule or an elementary school adds late afternoon classes). Both types of changes would affect the load profile and may increase peak demand.

Although not addressed in this study, a changing load shape may affect the duration of T&D equipment overloads. If the duration of peak loading increases, the amount of T&D equipment damage per overloading event may also increase. For this study, the peak load shape is treated as if it does not change from one year to the next.

Key DER-related Uncertainties

DER Power Rating

One key design challenge related to modular distributed energy resources (DERs), is that modular resources, in general, can deliver a relatively small amount of power relative to the load carrying capacity of the T&D capacity that the DER supplements. Uncertainty about whether a given amount of DER capacity can supply the amount of power needed is based on uncertainty about the level of peak load that will occur.

DER Reliability

DER reliability is an important criterion affecting the merits of DERs used *in lieu* of T&D capacity. When using the risk-adjusted-cost framework to compare DER alternatives, the cost associated with equipment failure must be addressed if such failure affects the grid.

DER Fuel

Depending on the type and efficiency of a DER, there will be fuel-related risk. That risk is driven by the price magnitude and volatility, availability and deliverability of the fuel needed.

DER Technology

DER prime movers and/or other subsystems (or the integration thereof) may be new or relatively new. To the extent that there is uncertainty about system reliability or about how to operate the equipment – because the technology is new – there is risk. For this study, no specific consideration is given to uncertainty related to use of new DER technology.

DER Equipment Performance and Reliability Degradation

In general, older equipment may have degraded performance and/or may be less reliable relative to newer equipment. Manufacturing errors or design flaws can cause equipment failure early in the equipment’s life. Conversely, newer equipment that has already been in service may be less prone to failure. In some cases, the DER may have been operated such that its reliability has degraded. No specific consideration is given to uncertainty related to DER equipment age or reliability degradation for this study.

DES Discharge Duration Adequacy

A key design challenge unique to modular distributed electricity storage (DES) is the possibility that there will not be enough stored energy to deliver the amount of energy needed during a given period of time. Uncertainty about whether DES can supply the amount of energy needed is driven mostly by uncertainty regarding a) the amount of inherent peak load growth that will materialize, b) block load additions, c) weather (extreme weather affects both the magnitude and the duration of demand peaks) and d) load shape change. The DES discharge duration adequacy uncertainty was not addressed for this study.

Electric Supply Uncertainties

Although not within the scope of this study, uncertainty related to electric supply could be included in a risk-adjusted-cost assessment of alternatives (to T&D equipment) to provide capacity on the margin. Some important electric supply uncertainties that may have implications for T&D upgrade choices include generation capacity adequacy, electric supply reliability and generation fuel price and availability.

Appendix J – T&D Equipment Derating for High Ambient Temperatures

For this study, a realistic but simplistic dataset and methodology are used to account for the derating of T&D equipment due to high ambient temperatures. Although the approach used is based on actual data, it has at least one notable shortcoming: The same “derating curve” is used for all T&D equipment when, in reality, it may not be appropriate to use curves like the one used here to characterize derating of various equipment types and vintages.

Data and Calculation

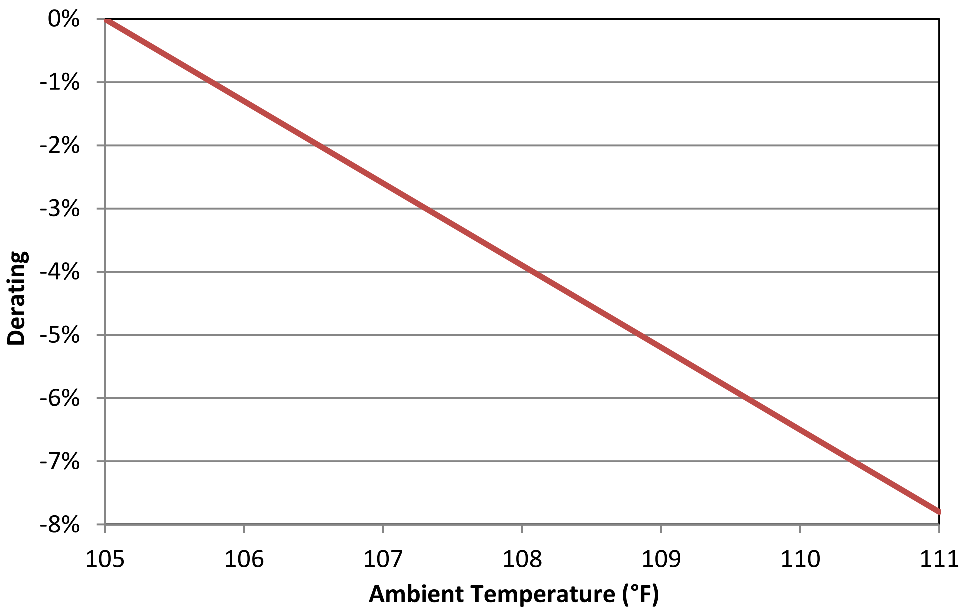
The calculations used to establish the derating for T&D equipment is as follows. The temperature-specific load carrying capability (LCC) is calculated as:

1 + ((Design Temperature – Ambient Temperature) * 0.013)).

And the derating is calculated as the adjusted load carrying capacity minus one.

Results

Figure J-1 shows the temperature-related derating curve, for a design temperature of 105°F, used for this report.



Ambient Temp.	105	106	107	108	109	110	111
Effective LCC	1.000	0.987	0.974	0.961	0.948	0.935	0.922
Derating	0.000	-0.013	-0.026	-0.039	-0.052	-0.065	-0.078

Figure J-1. T&D equipment derating for ambient temperature.

Appendix K – T&D Equipment Loss-of-life Estimation

For this study, a realistic, but simplistic, dataset is used to account for damage to T&D equipment due to overloading. See Appendix O for an introduction to the topic of the effects of overloading on electrical system component life.

T&D Equipment Damage Due to Overloading

For a given level of T&D equipment overload, the physical damage is estimated in terms of loss-of-life in years. As described in Appendix L, the effective overload for a given event is a function of a) real-time demand exceeding T&D capacity, b) the prevailing ambient temperature when the overload occurs and c) the derating of the equipment, if any, due to high ambient temperature.

Overloading Thresholds

No appreciable T&D equipment damage is assumed to occur for overloading below 4%. Overloading exceeding 11% is assumed to result in outages whose duration lasts from a few minutes to about five hours (as a function of temperature and overload magnitude).

Effects of Overload Duration on Equipment Loss-of-life

For simplicity, no attempt was made to account for the effect of overload *duration* on equipment damage. A given overload magnitude was treated as an overload event, resulting in a specific amount of T& D equipment life loss, without regard to how long the overload occurred. In reality, overload duration is an important criterion that would probably be included in a more robust version of the evaluation demonstrated in this report.

Equipment Damage Curve

Importantly, there is a relative dearth of generic and readily obtainable information available regarding T&D equipment damage due to overloading. Consequently, the equipment loss-of-life assumptions used for the evaluation in this report are derived based on limited actual data and on engineering judgment. Nonetheless, the data used is intended to be realistic.

Figure K-1 shows the generic T&D equipment "damage curve" used for this evaluation. Values on the horizontal (X) axis indicate the total loading (where 100% equals the design load carrying capacity of the T&D equipment).

Values on the left vertical (Y) axis indicate the loss-of-life per overloading event as percentage of the total life of the equipment. Values on the right vertical axis reflect the loss-of-life – associated with a given level of equipment loading – in years.

Note that the values on the second (right) Y axis of Figure K-1 reflect a 40-year useful life for T&D equipment. For example, based on the damage curve: If overloading is about 8% (*i.e.,* total load is 108% of the equipment's load carrying capacity), then loss-of-life is estimated to be about 1%. Continuing with the example: 1% of 40 years is 0.4 year.

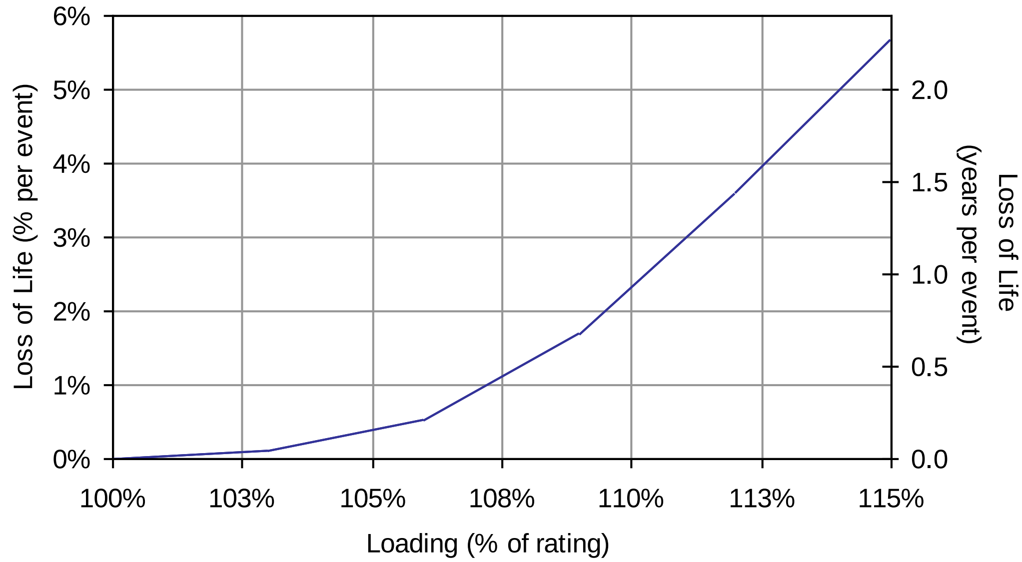


Figure K-1. T&D equipment damage curve reflecting loss-of-life as function of equipment loading.

To be clear: Even though there are only twelve years of remaining life assumed for the existing T&D equipment, the loss-of-life estimates (reflected in the damage curve) are based on the normal useful life for new equipment of 40 years.

Note that, for simplicity, the same data is used for all T&D equipment types – though, in reality, overloading affects each type of equipment differently.

Appendix L – T&D Equipment Overload Events' Magnitude, Frequency and Duration

Estimating T&D Equipment Overloading

As illustrated in Figure L-1, each end state of the probability tree (which is shown in its entirety in Appendix H, Table H-2) represents one possible outcome (scenario) with a specific probability of occurrence, a specific level of T&D equipment overloading (effective overload), and a specific cost associated with that level of overloading.

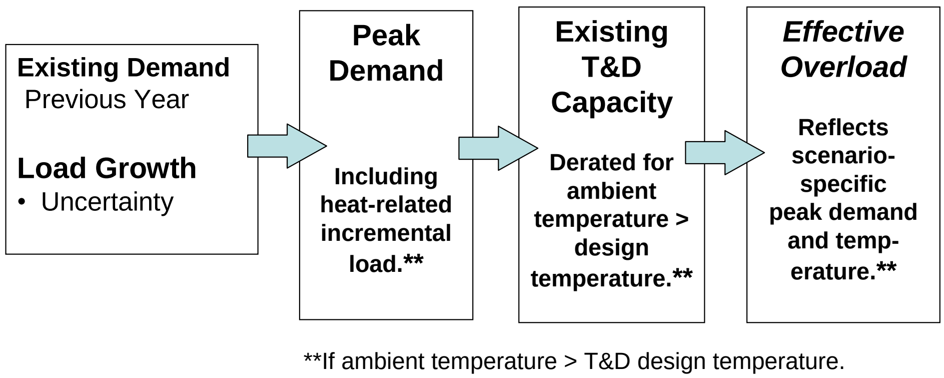


Figure L-1. Estimating scenario-specific T&D equipment effective overload level.

Excess Demand

The first step in calculating overload level is to estimate the amount of excess customer demand. That is the amount of customer load which exceeds the T&D equipment's rated load-carrying capacity (*i.e.*, in excess of the equipment's design rating). Excess demand calculations for all 27 end states in the probability tree generated for the study are shown in Appendix H.

Ambient Temperature Effect on Demand

Incremental customer demand due to high ambient temperatures is driven primarily by air conditioning loads. For this evaluation, the effect of ambient temperature on demand is assumed to be as follows: For maximum ambient temperature equal to the design temperature of 105°F (90% chance), there is no incremental demand. If ambient temperature is 107.5°F (7.5% chance), then load is 5% higher than it would be at the design temperature of 105°F. If ambient temperature is 110°F (2.5% chance), then load is 10% higher than it would be at the design temperature. Adding the peak load in the previous year, the inherent load growth, block load additions and weather-related load effects yields the amount of load that exceeds the T&D equipment's rating (load exceeding rating).

T&D Capacity Derating for High Ambient Temperatures

As ambient temperature increases, the T&D equipment load-carrying capacity decreases. Details about how T&D equipment is derated to account for effects of high ambient temperature for this study are provided in Appendix J.

Effective Overload

For this report, the combined effect of load exceeding rating *plus* equipment derating is referred to as the *effective overload*. That is, load exceeding rating at a given ambient temperature is added to the T&D equipment derating (at the same ambient temperature) to establish the net effect on the equipment due to overloading (for the given ambient temperature). Effective overload is expressed as a percentage of the equipment's design rating (*i.e.*, rated load-carrying capacity at the design temperature).

Damage and Outage Events

As illustrated in Figure L-2, a given level of T&D equipment overload may lead to a damage event and/or an outage event. A damage event reduces the useful life of T&D equipment, leading to a financial loss. Outage event costs addressed in this study include a) utility outage "response cost," b) utility lost revenue, and c) financial losses incurred by utility customers. The cost associated with a given level of overload is the sum of the cost associated with the damage, if any, plus the cost associated with an outage, if one occurs.

In this study, overloads of less than 4% (overload "floor") are ignored, overloads between 4% and 10% cause damage, and overloads exceeding 10% of the T&D rating (overload ceiling) result in T&D equipment damage and service outages. Details about equipment damage-related assumptions used in this report are provided in Appendix K.

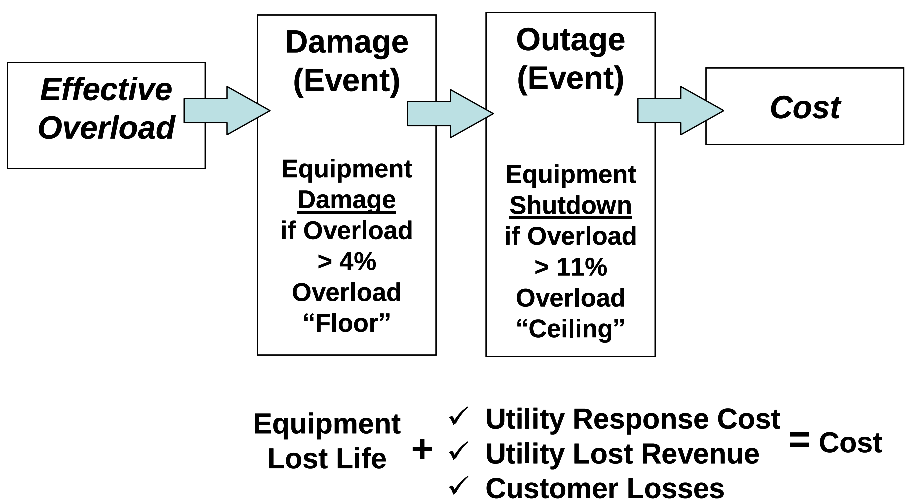


Figure L-2. Scenario-specific damage and outage events.

Outage Event Durations

A key criterion that affects overloading-related cost is the duration of overloading events. Specifically, overloading duration is needed to calculate the following customer outage-related costs: a) utility lost revenue and b) customer cost of unserved energy.

Unfortunately, information about overload durations is not readily available. So, generic data – shown in Table L-1 – was developed for this analysis based on a combination of the authors 'judgment and familiarity with the subject. That data indicates the assumed outage event duration as a function of two parameters: 1) excess demand (actual load that exceeds the T&D equipment's load-carrying capacity design rating) and 2) ambient temperature.

Table L-1. Outage Event Duration as a Function of Excess Demand and Ambient Temperature

Ambient Temperature =>	110ºF	111ºF	112ºF	113ºF	114ºF	115ºF	116ºF
Demand 5.0% > Rating	0.08	0.23	0.39	0.54	1.00	1.26	1.57
Demand 7.5% > Rating	0.39	0.54	1.00	1.26	1.57	1.88	2.19
Demand 10.0% > Rating	0.58	0.93	1.27	1.62	1.97	2.32	2.66
Demand 12.5% > Rating	1.54	1.93	2.47	2.91	3.37	3.83	4.30

Based on the data in Table L-1: If actual load exceeds the design rating by a few percentage points, and if temperature is relatively low, then the event duration is short – much less than an hour. If the excess demand and ambient temperature are both high, then overloading events may last for up to 4.8 hours.

A key facet to the rationale used to develop these values is as follows: Until load exceeding rating and/or ambient temperature drop – so that equipment will not be overloaded – the T&D system cannot be re-energized without causing: a) additional service disruptions, and/or b) T&D equipment damage and/or c) poor power quality.

Overloading Event Frequency

Some of the most important data needed for risk-adjusted cost evaluations described in this report are those related to the frequency of outage events due to overloading. As with information about overloading event duration, limited data was readily available to characterize overload event frequency. So, the authors used familiarity with the subject and best judgment to develop assumed values (frequency distribution) for excess demand values which underlies the frequency of overloading events. The assumed frequency distribution for excess demand events is shown in Figure L-3.

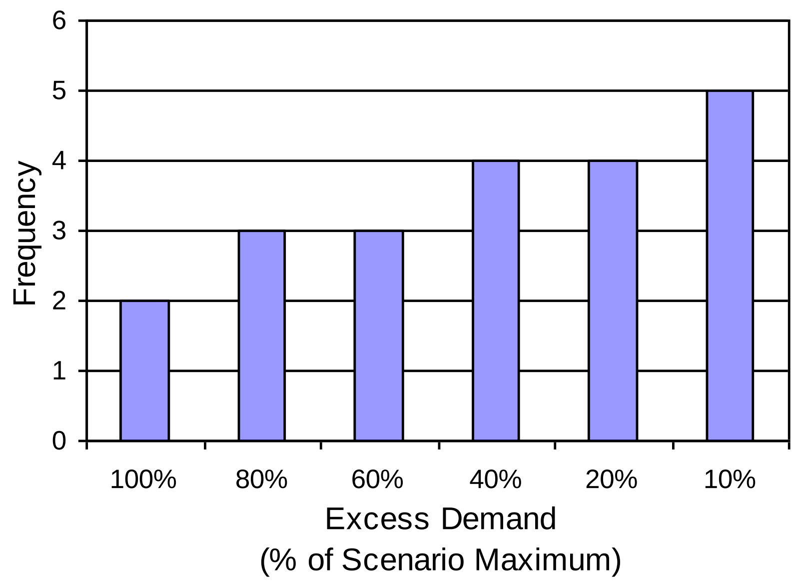


Figure L-3. Frequency of excess demand and overloading events' magnitude.

Values plotted on the horizontal axis of Figure L-3 indicate the magnitude of excess demand for each occurrence. Values plotted on the vertical axis of Figure L-3 indicate the frequency of occurrence for scenario-specific excess demand events. That frequency distribution is applied to the scenario-specific maximum excess demand.

Consider an example: The maximum excess demand for a given scenario is 840 kW (maximum load exceeds the existing T&D equipment's 12,000 kW rating by 7%). In that example, there are two events involving the maximum excess demand, three events whose excess demand is 80% of the maximum (0.8 * 840 kW = 672 kW), three events whose excess demand is 60% of the maximum (0.6 * 840 = 504 kW), etc.

Readers should recall that effective *overload* – as distinct from excess *demand* – is a function of both a) excess demand associated with end-users' power draw and b) derating of the T&D equipment (reduced load carrying capacity) related to the effect that high temperature has on the equipment's load-carrying capacity.

Note that, as described in Section 3.6.2, effective overload events that are less than the 4% overload floor are ignored (*i.e.,* they are treated as if they cause no appreciable T&D equipment damage and they do not result in electric service outages).

Note also that the maximum ambient temperature and the T&D equipment derating are the same for all events within a scenario.

Appendix M – The Revenue Requirement Legacy

Revenue Requirement

Historically, regulated investor-owned* electric utilities (IOUs) have used a somewhat unique framework for raising the capital needed to build the utility infrastructure.[M1]

This framework contains two key elements. First, the utility is given a monopoly franchise in a specific region and receives a fairly certain, though regulated, rate-of-return on investments in infrastructure. Second, in exchange for what it receives under the first element, the utility accepts an "obligation to serve," and it agrees to provide electric service with a specified level of quality and reliability.

With a regulated and fairly certain value proposition – including what might be characterized as an implicit shield against most risk – many otherwise unwilling investors purchased utility stocks and bonds. With that capital, IOUs were able to achieve the economies of scale needed to generate low-cost electricity. Also, the companies that generated electricity often built and owned the wires and transformers needed to deliver the electricity. Although those 'vertically integrated' utilities provided transmission and distribution, generation was viewed as the core business.

Today, the same general approach is used, although IOUs are less likely to own all of the generation needed to serve their customers. Also, transmission and distribution have become relatively more important elements of utilities' business.

One unique facet of this approach is that utility prices are based on what is called the *revenue requirement.* The revenue requirement is the level of revenue necessary to pay all utility equipment investment-related costs, including return of capital, interest, dividends and taxes. Thus, the utility price is entirely "cost-based," with profit set by regulators, rather than being a function of cost plus normal market forces. See Appendix E for details about how revenue requirements are calculated for this report.

It is important to note that often the term revenue requirement is meant to include only equipment-investment-related costs listed in the previous paragraph. Under that definition, the revenue requirement does not include utility expenses, especially fuel and labor. The expenses are treated as "pass-throughs." Consequently, utility customers pay just what the utility pays (plus the cost for overhead charges) for most variable costs such as fuel purchases and labor.

Some important implications are worth noting:

- Essentially, "profit" for an IOU is a set amount based on regulator-specified returns on investments in equipment.

*Two other types of utilities are 1) publicly-owned municipal utilities (munis) as described by the American Public Power Association (APPA, http://publicpower.org/) and 2) electric cooperatives or rural co-ops (co-ops) which are privately owned by the members (see the National Rural Electric Cooperative Association (NRECA) website for details at http://nreca.coop/).

- IOUs do not derive profit or dividends from a direct “markup” on variable costs such as fuel or labor. Consequently, they have limited direct incentive to minimize expenses.
- IOUs derive profit (stockholder dividends) entirely from investments in utility equipment. Therefore, they have an inordinate incentive to build, and they have less direct incentive to buy needed services that involve expenses or to optimize capital expenditures (*i.e.,* to serve the most demand for the lowest total investment in equipment possible).
- Under the revenue requirements method, if revenues from all utility sales are roughly equal to all utility equipment costs, expenses, dividends, and taxes, then there is limited direct incentive for utilities to reduce overall cost by reducing risk. So, an undetermined amount of risk – some that may be avoidable – is inadvertently passed on to ratepayers without being evaluated.
- For the most part, customers in areas with high direct cost of service pay roughly the same price as customers in areas where the direct cost of service is low. This could be viewed as a subsidy paid by customers where cost of service is relatively low. More importantly for this study, this situation reduces the incentive for electricity distribution companies (DISCOs) to evaluate situation-specific risk for circumstances where risk may be relatively high.
- Revenue-requirements-based pricing tends to give utilities an incentive to build what is sometimes referred to as “concrete-and-steel-reinforced” infrastructure additions. Unless an investment is clearly imprudent and/or is not consistent with established engineering criteria, the investment is added to a utility’s “rate base” and utility ratepayers must pay for it. In the new electricity marketplace, this phenomenon may become less common as distribution companies seek ways to reduce cost, on the margin, of the utility’s capacity and optimize capital investments.
- Several types of risk alluded to in the previous bullets could be called “distributed risk” because the risk associated with any particular project addressing utility capacity needs-on-the margin is spread among all customers.

Expenses as Pass Throughs

As noted above, IOUs do not derive profit from variable costs such as fuel or labor. That is because such expenses are treated as a “pass-through” (*i.e.,* the cost for fuel is passed on directly to end-users on a dollar-for-dollar basis with no mark-up). One implication is that utilities have limited direct incentive to reduce expenses. Also, utilities usually have very tight expense budgets, so alternatives that are expense based – such as generator rentals – may face budgetary constraints not directly related to the financial merits of the alternative.

Reference

[M1] Hirsh, Richard F. *Technology Transformation in the American Utility Industry*. Cambridge University Press. 1989.

Appendix N – Risk Calculation Worksheets, Examples

Risk Calculation Worksheets

This appendix provides an overview of the process and Excel worksheets used to calculate risk. Risk calculations are shown for two cases: 1) do nothing (no DER) and 2) deploy 500 kW of "perfect" DER (*i.e.,* DER that is 100% reliable such as geographically targeted demand response implemented using direct load control).

Scenario-specific risk calculations are shown for one specific *featured scenario* – scenario #26 – for both of those cases. (See Tables N-1 and N-4 showing scenario-specific results for the features scenario).

Next, detailed *total risk* calculations for all 27 scenarios are provided for the two cases. (See Tables N-2 and N-5 which depict the detailed results for the two cases). Note that the featured scenario – scenario #26 – is shown on line 10 of those detailed results tables.

Finally, a *results summary* for all 27 scenarios is provided for both cases. (See Tables H-3 and H-6 which depict the results summary for both cases.)

See also the "probability table" Table H-2 in Appendix H which shows how scenario-specific excess demand is calculated.)

The worksheets shown below are used as follows. As shown in Figure 5 in Section 4.1.3.1 of the report, risk is estimated for a range of DER power ratings, ranging from none (*i.e.,* yields risk for the do nothing alternative) to 1,500 kW, in increments of 50 kW. So the process starts with the do nothing alternative (*i.e.,* with no DER capacity) and is repeated 30 times until the total amount of DER added is 1,500 kW.

Results for the Do Nothing Case

Do Nothing Case, Featured Scenario

Risk calculations for the featured scenario – scenario #26 – are provided for the do nothing case in the scenario risk worksheet shown in Table N-1. For the do nothing case, scenario #26 is characterized by

1. Excess demand of 9.375%
2. Maximum ambient temperature of 107.5°F
3. Maximum effective overload of 12.625% (1,516 kW)
4. Five outage events
5. Twenty-one total damage events
6. Cost (for damage and outages) of $897,823
7. Cumulative Loss-of-life of 9.2 years
8. A modest 0.53% likelihood of occurrence (as shown in Table N-2, line #10)

Do Nothing Case, All Scenarios

Detailed total risk calculations for all 27 scenarios are provided for the do nothing case in Table N-2. Those results are summarized in Table N-3.

In Table N-2, there are eight scenarios – with a combined probability of 84% – for which the maximum overload does not exceed the overload floor of 4% (*i.e.,* there are no T&D equipment damage or outage events for those scenarios).[*]

Expected value results for all scenarios are shown in the bottom row (labeled Expected Value) of Table N-2. They include the following:

1. Ambient temperature of 105.3°F
2. Effective overload of 2.82% (339 kW)
3. Equipment loss-of-life of 0.89 years costing $35,260
4. 0.43 outage events would cost the utility $1,310 for labor and $2,540 in lost revenues
5. Utility customers would incur $60,999 in outage related costs
6. Total "cost" (*i.e.*, risk) of $99,116

Summary results for all scenarios for the do nothing case shown in Table N-3 include the following:

1. There is about a 16.3% chance that the maximum effective overload will exceed the 4% overload floor.
2. There are 6 scenarios with maximum effective overload is between 4% and 10%. They have a combined probability of 10.44%.
3. There are 13 events – with a combined probability of 5.9% – involving effective overload that exceeds the 10% overload ceiling. For any of those 13 scenarios damage and outages will occur.

[*] Those eight scenarios (#16, 7, 22, 13, 4, 1, 10, 19) are shown in Table N-2, lines 20 through 27. The combined probability of 84% is the sum total of individual scenario probabilities.

Table N-1. Overloading and Risk Details for the Featured Scenario, Do Nothing Case

Scenario Risk Calculations

Case: Example Case

Scenario Excess Demand [1]	9.375%	Overload "Floor" [2]	4.0%
Scenario Temperature	107.5ºF	Overload "Ceiling" [3]	10.0%
DER Capacity (kW)	0	☐ Include DER?	

Event Occurrences Assumed	2	3	3	4	4	5	0	0
Event Overload (% of Scenario Excess Demand)	100%	80%	60%	40%	20%	10%	0%	0%
Excess Demand [4]	**9.375%**	7.500%	5.625%	3.750%	1.875%	0.938%	0.000%	0.000%
Equipment Derating [5]	**3.250%**	☑ Include T&D Equipment Derating?						
DER Capacity	**0.000%**							
"Effective" Overload [6]	**12.625%**	**10.750%**	**8.875%**	**7.000%**	**5.125%**	**4.188%**	**3.250%**	**3.250%**
Outage(s) Occur?	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Damage Occurs?	TRUE	TRUE	TRUE	TRUE	TRUE	TRUE	FALSE	FALSE

[1] Demand exceeding equipment design rating.

[2] Less overloading than this causes insignificant damage.

[3] More overloading than this causes shutdowns/outages.

[4] Demand exceeding equipment rating.

[5] Equipment's reduced load carrying capacity due to high ambient temperature (relative to design temperature).

[6] Excess demand plus equipment derating.

Outages (scenario-specific)

Events	2	3						
Outage Duration (hours/event)	2.688	1.819						
"Unserved Energy" (MWh)	35.3	23.5						
"Unserved Energy" Cost per Event ($)	126,932	84,434						
"Unserved Energy" Cost Total ($)	253,864	253,303						
Lost Revenue ($)	10,585	10,562						

Total Values

Outage Events	5
Hours	10.8
Unserved kWh ($)	507,167
Lost Rev. ($)	21,147
Labor ($)	5,000
	533,314

Damage (scenario-specific)

Events	2	3	3	4	4	5		
Loss-of-life, per Event (years)	0.73	0.60	0.49	0.41	0.33	0.30		
Loss-of-Life for "bin" (years)	1.5	1.8	1.5	1.6	1.3	1.5		
Loss-of-life, Cumulative (years)	1.5	3.3	4.7	6.4	7.7	9.2		
Cost Total, Cumulative ($)	57,861	129,592	187,866	252,854	305,682	364,509		

Total Values

Damage Events	21
Loss-of-life (years)	9.2
Damage ($)	364,509
All Costs	**897,823**

If effective overload > overload ceiling
Then use loss-of-life estimate for overload ceiling.
Otherwise use loss-of-life estimate for effective overload

Table N-2. Overloading and Risk Details, Do Nothing Case, All Scenarios

Scenario							Damage		Utility Outage Costs				Utility Total		Customer Outage Cost			Risk		Effective Overload†		
Line#	Scenario	Probability	Excess Demand (kW)	Excess Demand (%)	Ambient Temp. (°F)	Effective Overload† (%)	Loss-of-life (years)	Cost ($000)	# of Events	Labor Cost ($000)	Total Outage Time (hours)	Lost Revenues ($000)	Gross ($000)	Probability Weighted ($000)	Average Duration (hours)	Unserved Energy Cost ($000)	Probability Weighted ($000)	Gross ($000)	Probability Weighted ($000)	Overload > 4.0%	Overload > 7.0%	Overload > 10.0%
1	27	0.18%	1,750	14.6%	110.0	21.1%	13	515	12	12.0	45.6	89.9	617	1.1	3.8	2,155	3.77	2,772	4.85	✓	✓	✓
2	18	0.53%	1,640	13.7%	110.0	20.2%	13	515	12	12.0	44.7	87.7	614	3.2	3.7	2,103	11.04	2,718	14.27	✓	✓	✓
3	9	0.18%	1,530	12.8%	110.0	19.3%	13	515	12	12.0	43.8	85.5	612	1.1	3.7	2,051	3.59	2,663	4.66	✓	✓	✓
4	24	0.25%	1,475	12.3%	110.0	18.8%	13	515	12	12.0	43.4	84.4	611	1.5	3.6	2,025	5.06	2,636	6.59	✓	✓	✓
5	15	0.75%	1,365	11.4%	110.0	17.9%	13	515	12	12.0	42.5	82.3	609	4.6	3.5	1,974	14.80	2,583	19.37	✓	✓	✓
6	6	0.25%	1,255	10.5%	110.0	17.0%	13	515	12	12.0	41.6	80.1	607	1.5	3.5	1,922	4.81	2,529	6.32	✓	✓	✓
7	21	0.08%	1,200	10.0%	110.0	16.5%	13	515	12	12.0	41.1	79.1	606	0.5	3.4	1,897	1.42	2,503	1.88	✓	✓	✓
8	12	0.23%	1,090	9.1%	110.0	15.6%	13	502	12	12.0	39.2	75.1	589	1.3	3.3	1,800	4.05	2,389	5.38	✓	✓	✓
9	3	0.08%	980	8.2%	110.0	14.7%	12	480	8	8.0	28.7	54.9	543	0.4	3.6	1,317	0.99	1,860	1.40	✓	✓	✓
10	26	0.53%	1,125	9.4%	107.5	12.6%	9.2	365	5	5.0	10.8	21.1	391	2.1	2.2	507	2.66	898	4.71	✓	✓	✓
11	17	1.58%	1,020	8.5%	107.5	11.8%	8.8	347	5	5.0	9.0	17.5	370	5.8	1.8	421	6.62	791	12.45	✓	✓	✓
12	8	0.53%	915	7.6%	107.5	10.9%	8.4	331	2	2.0	3.8	7.3	341	1.8	1.9	175	0.92	515	2.71	✓	✓	✓
13	23	0.75%	863	7.2%	107.5	10.4%	6.7	266	2	2.0	3.3	6.4	274	2.1	1.7	154	1.16	428	3.21	✓	✓	✓
14	14	2.25%	758	6.3%	107.5	9.6%	6.4	252					252	5.7				252	5.67	✓	✓	
15	5	0.75%	653	5.4%	107.5	8.7%	6.0	239					239	1.8				239	1.79	✓	✓	
16	20	0.23%	600	5.0%	107.5	8.3%	5.9	233					233	0.5				233	0.52	✓	✓	
17	11	0.68%	495	4.1%	107.5	7.4%	5.6	220					220	1.5				220	1.49	✓	✓	
18	2	0.23%	390	3.3%	107.5	6.5%	4.1	163					163	0.4				163	0.37	✓		
19	25	6.30%	500	4.2%	105.0	4.2%	0.6	23.5					23.5	1.5				23	1.48	✓		
20	16	18.90%	400	3.3%	105.0	3.3%																
21	7	6.30%	300	2.5%	105.0	2.5%																
22	22	9.00%	250	2.1%	105.0	2.1%																
23	13	27.00%	150	1.3%	105.0	1.3%																
24	4	9.00%	50	0.4%	105.0	0.4%																
25	1	2.70%			105.0	0%																
26	10	8.10%			105.0	0%																
27	19	2.70%			105.0	0%																
Expected Value*			290	2.41%	105.3	2.82%**	0.89	35.26	0.43	0.43	1.31	2.54	**Utility 38.2**		0.15	**User 60.9**		**Total 99.1**		19	17	13

† A.k.a scenario-specific *maximum* effective overload = excess demand + effects related to T&D derating for high temperature.

* Probability weighted.

** 2.82% * 12,000 kW existing T&D capacity = 339 kW.

	≥ 4%	4% to 10%	≥ 10%
Probability	16.30%	10.43%	5.88%

Table N-3. Overloading and Risk Results Summary, Do Nothing Case, All Scenarios

	All End-States Raw	Over-load* > 0%	Over-load* > 4.0%	Over-load* > 7.0%	Over-load* > 10.0%
Qualifying Scenarios	27	24	19	17	13
Probability-of-occurrence	100%	86.5%	16.3%	9.8%	5.9%
Average Effective Overload (kW)**	**339**	**391**	**1,083**	**1,465**	**1,726**
(%)	**2.82%**	**3.26%**	**9.02%**	**12.21%**	**14.38%**
Deferral Value*** ($/kW-year)	273	236	85.3	63.1	53.5

* *Effective* Overload: Excess Demand + Derating for High Temperature.

** Weighted average values *for qualifying scenarios*.

*** Revenue Requirement for upgrade ($92,400 per year) / Avg. Effective Overload (kW).

Results for the 500kW of Perfect DER Case

The next results shown (below in Tables N-4 through N-6) reflect all the same circumstances described above with one difference: 500 kW of perfectly reliable DER is added to the grid to serve peak demand on the margin. Doing so is has the net effect of reducing the excess demand by the rating of the DER (*i.e.,* in this case, by 500 kW).

500 kW of Perfect DER Case, Featured Scenario

As shown for the featured scenario in Table N-4: When adding 500 kW of perfect DER capacity (4.167% of the existing T&D capacity's load carrying capacity of 12,000 kW), the scenario-specific maximum effective overload is 8.458% (for the do nothing case it is 12.625%).

That 8.458% effective overload reflects the same 9.375% excess demand plus and 3.25% T&D equipment derating due to high ambient temperature as the do nothing case minus 4.167% DER capacity (500 kW).

Adding the 500 kW of perfect DER eliminates the outage events entirely, so there are no outage-related costs incurred for the featured scenario. Nevertheless, as shown for the featured scenario in Table N-4, there are eight overloading events whose effective overload exceeds the overload floor (4%), so there is some damage to the existing T&D equipment. Also shown in Table N-4: The T&D equipment's remaining life is reduced by 3.1 years at a cost of $121,759.

500 kW of Perfect DER Case, All Scenarios

Table N-5 – the second version of the total risk worksheet – shows risk for all 27 scenarios of the 500 kW of perfect DER case. (The featured scenario, # 26, is shown on line 10 of that total risk worksheet.) Results in Table N-5 are summarized in Table N-6.

In Table N-5, there are 11 scenarios – with a combined probability of 91% – for which there is no effective overload (maximum overload does not exceed the overload floor of 4%).[*] There are 16 scenarios – with a combined probability of 9.1% – whose excess demand exceeds the overload floor of 4% (*i.e.,* there is T&D equipment damage for those scenarios). Further, there are 9 scenarios – with a combined probability of 2.5% – whose excess demand exceeds the overload ceiling of 10% (*i.e.,* there is T&D equipment damage and outages events for those scenarios).
Expected value results for all scenarios are shown in the bottom row (labeled Expected Value) of Table N-5. They include the following:

1. Ambient temperature of 105.3°F
2. Effective overload of -1.35% (-162 kW) – in other words, there is no overloading
3. Equipment loss-of-life of 0.33 years costing $13,050
4. 0.14 outage events would cost the utility $140 for labor and $930 in lost revenues
5. Utility customers would incur $22,400 in outage related costs
6. Total "cost" (*i.e.,* risk) of $36,500

[*] Those eleven scenarios (#11, 2, 25, 16, 7, 22, 13, 4, 1, 10, 19) are shown in Table N-5, lines 17 through 27. The combined probability of 91% is the sum total of individual scenario probabilities.

Table N-4. Overloading and Risk Details, Featured Scenario, 500 kW Perfect DER Case

Scenario Risk Calculations

Case: Example Case

Scenario Excess Demand [1]	9.375%	Overload "Floor" [2]	4.0%					
Scenario Temperature	107.5ºF	Overload "Ceiling" [3]	10.0%					
DER Capacity (kW)	500	☑ Include DER?						
Event Occurrences Assumed	2	3	3	4	4	5	0	0
Event Overload (% of Scenario Excess Demand)	100%	80%	60%	40%	20%	10%	0%	0%
Excess Demand [4]	**9.375%**	7.500%	5.625%	3.750%	1.875%	0.938%	0.000%	0.000%
Equipment Derating [5]	**3.250%**	☑ Include T&D Equipment Derating?						
DER Capacity	**4.167%**							
"Effective" Overload [6]	**8.458%**	**6.583%**	**4.708%**	**2.833%**	**0.958%**	**0.021%**	**-0.917%**	**-0.917%**
Outage(s) Occur?	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE	FALSE
Damage Occurs?	TRUE	TRUE	TRUE	FALSE	FALSE	FALSE	FALSE	FALSE

[1] Demand exceeding equipment design rating.

[2] Less overloading than this causes insignificant damage.

[3] More overloading than this causes shutdowns/outages.

[4] Demand exceeding equipment rating.

[5] Equipment's reduced load carrying capacity due to high ambient temperature (relative to design temperature).

[6] Excess demand plus equipment derating.

Outages (scenario-specific)

Events								
Outage Duration (hours/event)								
"Unserved Energy" (MWh)								
"Unserved Energy" Cost per Event ($)								
"Unserved Energy" Cost Total ($)								
Lost Revenue ($)								

Total Values

Outage Events	0
Hours	0.0
Unserved kWh ($)	0
Lost Rev. ($)	0
Labor ($)	0
	0

Damage (scenario-specific)

Events	2	3	3					
Loss-of-life, per Event (years)	0.47	0.39	0.32					
Loss-of-Life for "bin" (years)	0.9	1.2	1.0					
Loss-of-life, Cumulative (years)	0.9	2.1	3.1					
Cost Total, Cumulative ($)	37,437	84,060	121,759					

If effective overload > overload ceiling
Then use loss-of-life estimate for overload ceiling.
Otherwise use loss-of-life estimate for effective overload

Total Values

Damage Events	8
Loss-of-life (years)	3.1
Damage ($)	121,759
All Costs	**121,759**

Table N-5. Overloading and Risk, 500 kW Perfect DER Case, All Scenarios

Scenario							Damage		Utility Outage Costs				Utility Total		Customer Outage Cost			Risk		Effective Overload†		
Line#	Scenario	Probability	Excess Demand (kW)	Excess Demand (%)	Ambient Temp. (°F)	Effective Overload† (%)	Loss-of-life (years)	Cost ($000)	# of Events	Labor Cost ($000)	Total Outage Time (hours)	Lost Revenues ($000)	Gross ($000)	Probability Weighted ($000)	Average Duration (hours)	Unserved Energy Cost ($000)	Probability Weighted ($000)	Gross ($000)	Probability Weighted ($000)	Overload > 4.0%	Overload > 7.0%	Overload > 10.0%
1	27	0.18%	1,750	14.6%	110.0	16.9%	9.7	383	8	8.0	28.1	56.4	447	0.8	3.5	1,352	2.37	1,799	3.15	✓	✓	✓
2	18	0.53%	1,640	13.7%	110.0	16.0%	9.2	364	8	8.0	27.1	54.1	426	2.2	3.4	1,297	6.81	1,722	9.04	✓	✓	✓
3	9	0.18%	1,530	12.8%	110.0	15.1%	8.7	345	5	5.0	19.2	38.4	388	0.7	3.8	920	1.61	1,308	2.29	✓	✓	✓
4	24	0.25%	1,475	12.3%	110.0	14.6%	8.4	334	5	5.0	18.6	37.0	377	0.9	3.7	888	2.22	1,265	3.16	✓	✓	✓
5	15	0.75%	1,365	11.4%	110.0	13.7%	8.0	315	5	5.0	17.2	34.1	354	2.7	3.4	819	6.14	1,173	8.80	✓	✓	✓
6	6	0.25%	1,255	10.5%	110.0	12.8%	7.5	297	5	5.0	15.9	31.3	334	0.8	3.2	750	1.88	1,084	2.71	✓	✓	✓
7	21	0.08%	1,200	10.0%	110.0	12.3%	7.3	289	5	5.0	15.0	29.5	323	0.2	3.0	707	0.53	1,030	0.77	✓	✓	✓
8	12	0.23%	1,090	9.1%	110.0	11.4%	6.9	272	2	2.0	6.4	12.5	286	0.6	3.2	299	0.67	585	1.32	✓	✓	✓
9	3	0.08%	980	8.2%	110.0	10.5%	5.3	211	2	2.0	5.2	10.2	223	0.2	2.6	245	0.18	467	0.35	✓	✓	✓
10	26	0.53%	1,125	9.4%	107.5	8.5%	3.1	122					122	0.6				122	0.64	✓	✓	
11	17	1.58%	1,020	8.5%	107.5	7.6%	2.9	113					113	1.8				113	1.78	✓	✓	
12	8	0.53%	915	7.6%	107.5	6.7%	1.8	71.4					71.4	0.4				71	0.37	✓		
13	23	0.75%	863	7.2%	107.5	6.3%	1.7	68.3					68.3	0.5				68	0.51	✓		
14	14	2.25%	758	6.3%	107.5	5.4%	1.6	62.3					62.3	1.4				62	1.40	✓		
15	5	0.75%	653	5.4%	107.5	4.5%	0.6	24.6					24.6	0.2				25	0.18	✓		
16	20	0.23%	600	5.0%	107.5	4.1%	0.6	23.2					23.2	0.1				23	0.05	✓		
17	11	0.68%	495	4.1%	107.5	3.2%																
18	2	0.23%	390	3.3%	107.5	2.3%																
19	25	6.30%	500	4.2%	105.0	0%																
20	16	18.90%	400	3.3%	105.0	-0.8%																
21	7	6.30%	300	2.5%	105.0	-1.7%																
22	22	9.00%	250	2.1%	105.0	-2.1%																
23	13	27.00%	150	1.3%	105.0	-2.9%																
24	4	9.00%	50	0.4%	105.0	-3.8%																
25	1	2.70%			105.0	-4.2%																
26	10	8.10%			105.0	-4.2%																
27	19	2.70%			105.0	-4.2%																
		Expected Value*	290	2.41%	105.3	-1.35% **	0.33	13.05	0.14	0.14	0.47	0.93	**Utility 14.1**		0.09	**User 22.4**		**Total 36.5**		16	11	9

† A.k.a scenario-specific *maximum* effective overload = excess demand + effects related to T&D derating for high temperature.

* Probability weighted.

** -1.35% * 12,000 kW existing T&D capacity = -162 kW.

	> 4%	4% to 10%	> 10%
Probability	9.10%	6.60%	2.50%

Table N-6. Overloading and Risk Results Summary, 500 kW Perfect DER Case, All Scenarios

	All End-States Raw	Over-load* > 0%	Over-load* > 4.0%	Over-load* > 7.0%	Over-load* > 10.0%
Qualifying Scenarios	27	18	16	11	9
Probability-of-occurrence	100%	10.0%	9.1%	4.6%	2.5%
Average Effective Overload (kW)**	**-162**	**950**	**1,008**	**1,351**	**1,700**
(%)	**-1.35%**	**7.92%**	**8.40%**	**11.26%**	**14.17%**
Deferral Value*** ($/kW-year)	n/a	97.3	91.6	68.4	54.4

* *Effective* Overload: Excess Demand + Derating for High Temperature.

** Weighted average values *for qualifying scenarios* .

*** Revenue Requirement for upgrade ($92,400 per year) / Avg. Effective Overload (kW).

Appendix O – The Effects of Overloading on Electrical System Component Life

Electric power components are typically assigned a capacity rating and an estimated life. The two parameters are related in that it is presumed that if the component does not experience loading in excess of its rating, it will achieve the stated useful life. Conversely, if the component does experience excessive loading, a reduction in useful life will result.

See Appendix K for a description of the loss-of-life-related cost estimation used for this report.

Conductors

The principal component of transmission and distribution (T&D) lines is the conductor. A conductor is a wire or bundle of wires made of aluminum, copper or steel that carries electric current. Because of resistance in the wires, conductor temperature will increase due to the heat generated by the resistive losses. Too much high-temperature operation will cause the wires (chiefly aluminum or copper) to lose their elasticity and strength — a process called *annealing*.

Annealing will cause the conductor to sag and violate clearance limits which will prematurely necessitate its replacement. This can happen after only a few minutes of overloading if the overload is severe enough and if protection systems do not act properly to disconnect the line. Sometimes splices or connectors in the line will overheat faster than the conductor itself, causing the connectors to fail. In such cases, the conductor may fall to the ground.

Transformers

Transformers are more complex devices than conductors. They consist of an iron core around which are wrapped various coils of insulated wires, inside a tank filled with insulating oil, along with connectors, bushings and various other small components.

Overloading causes excess heat in a transformer, the negative effects of which are degradation of the kraft paper insulation around the wires (leading to internal failures of the coils), excessive tank pressure or degradation of the insulating oil (either of which can cause catastrophic failures including explosions), leaking gaskets and leaking seals. Because the copper used in the windings is already soft (annealed) and is not under tension, overheating of transformers' conductors is generally not a significant concern.

Thermal cycling contributes to mechanical damage of transformers by loosening connections. Because of hysteresis in the transformer core, harmonics are generated by overloading – these harmonics can cause mechanical vibration of the transformer, contributing to physical damage. Overloading also assumes that faults near the transformer, when they occur, will be greater than normal, so there is increased likelihood of damage to the transformer from fault currents. Such damage can be manifested as coil failures, bushing flashovers, blown gaskets and seals, connector failures, oil explosions and fires and physical displacement of internal components due to electromechanical torque.

Underground Transmission

Transmission cables for underground circuits consist of copper conductors which are surrounded by paper or polyethylene insulation and jacketed by layers of polyvinyl chloride (PVC) or metal cladding. The cables are laid in conduit or trenches, and the conduit is filled with insulating oil or gas. Because they are not strung under tension, annealing is not a concern. High-temperature operation will generally cause the same type of insulation degradation as in transformers, as well as connector failures and fluid or gas leakage.

Circuit Breakers

Nominal overloads in continuous current do not ordinarily damage circuit breakers to any great degree. Nevertheless, the ability of a circuit breaker to operate properly and interrupt fault currents is a direct function of the fault current level. Fault current will be considerably higher if pre-fault current loading is higher than the design limit of the breaker.

When a circuit breaker detects a fault, it acts to open its contacts, across which an electrical arc will develop. The arc either extinguishes itself (as in an oil-filled breaker) or, in the case of a gas-filled breaker, a blast of air or other gas is directed at the arc to extinguish it. Failure to interrupt the current within the required time will destroy the circuit breaker and will likely severely damage the equipment it is designed to protect (transmission line, generator, *etc.*).

Even if the fault currents are within the design parameters of the breaker, each breaker operation results in some mechanical erosion of the contacts and production of contaminants in the oil or gas insulation. The higher the fault currents, the more the contacts are eroded and the more contaminants are produced, and the sooner the breaker will fail or must be overhauled.

References

Conductors

Morgan, V. T. Zhang, B. Findlay, D. *Effects of Temperature and Tensile Stress on the Magnetic Properties of a Steel Core from an ACSR Conductor*. IEEE Transactions on Power Delivery, Volume 11, Issue 4. October 1996.

Harvey, J. R. *Effect of Elevated Temperature Operation on the Strength of Aluminum Conductors*. IEEE Transactions on Power Apparatus and Systems, Volume PAS-91. September/October 1972.

Morgan, V. T. *The Loss of Tensile Strength of Hard-Drawn Conductors by Annealing in Service*. IEEE Transactions on Power Apparatus and Systems, Volume PAS-98. May/June 1979.

Livingston, A.E. *Aluminum Alloy Conductors for Overhead Transmission and Distribution Lines*. Canadian Electrical Association Western Zone Meeting, Vancouver, BC, Canada. March 1965.

Chen, S.L. Black, W.Z. Fancher, M.L. *High-Temperature Sag Model for Overhead Conductors*. IEEE Transactions on Power Delivery, Volume 18, Issue 1. January 2003.

IEEE Standard for Calculating the Current-temperature Relationship of Bare Overhead Conductors. November 1993.

Transformers and Underground Transmission

Morgan, V.T. *Effects of Frequency, Temperature, Compression and Air Pressure on the Dielectric Properties of a Multilayer Stack of Dry Kraft Paper*. IEEE Transactions on Dielectrics and Electrical Insulation, Volume 5, Issue 1. February 1998.

Sen, P. K. Pansuwan, S. *Overloading and Loss-of-Life Assessment Guidelines of Oil-Cooled Transformers*. Rural Electric Power Conference. April 29-May 1, 2001.

IEEE Guide for Loading Mineral-Oil-Immersed Transformers. IEEE C57.91-1995.

Heaton, A. G. Melas, E. *Determination of Effective Permittivity and Loss, as Functions of Temperature and Frequency, of Impregnated Paper Insulation by Measurements on Lengths of 132 kV Power Cables*. IEEE Conf. Publ. No. 67, 1970.

Parise, G. Rubino, G. Ricci, M. *Life Loss of Insulated Power Cables: An Integrated Criterium to Improve the ANSI/IEEE and the CENELEC/IEC Method for Overload Protect*ion. Conference Record of the Thirty-First Industrial Applications Society Annual Meeting, San Diego, California. October 1996.

Circuit Breakers

Stoving, P.N. Baranowski, J.F. *Interruption Life of Vacuum Circuit Breakers*. Proceedings of the Nineteenth International Symposium on Discharges and Electrical Insulation in Vacuum, Volume 2. September 18-22, 2000.

Sprague, M.J. *Service-life Evaluations of Low-voltage Power Circuit Breakers and Molded-case Circuit Breakers*. IEEE Transactions on Industry Applications, Volume 37, Issue 1. January/February 2001.

Chudnovsky, B.H. *Degradation of Power Contacts in Industrial Atmosphere: Plating Alternative for Silver and Tin*. Proceedings of the Forty-Ninth IEEE Holm Conference on Electrical Contacts. September 8-10, 2003.

Garzon, R.D. Schramm, H. Peelo, D. Landry, M. Muller, L. *HV Circuit Breaker Condition Monitoring And Life Extension*. IEEE Power Engineering Review, Volume 17, Issue 11. November 1997.

Osmokrovic, P. *The Irreversibility of Dielectric Strength of Vacuum Interrupters After Short-circuit Current Interruption*. IEEE Transactions on Power Delivery, Volume 6, Issue 3. July 1991.

Circuit Breakers, Switchgear, Substations and Fuses. ANSI/IEEE Standard C37. 1995.

Appendix P – Distribution

Hard Copies

Electronic Copies—Internal

Electronic Copies—External

[inside back cover]

Sandia National Laboratories